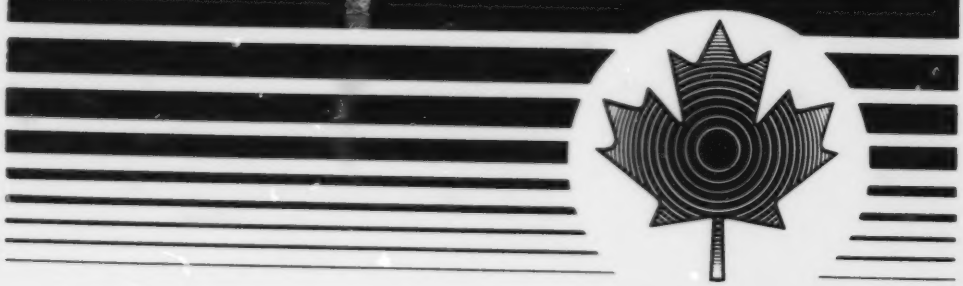
A PEAK LOAD FORECASTING MODEL CASE STUDY: THE ALBERTA INTERCONNECTED SYSTEM

K. MORGAN MACRAE



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Preface

The Institute is grateful for the helpful comments on earlier drafts of the Research Report by a four-member Advisory Committee comprised of three representatives from Alberta's electric utility industry and one representative from the Alberta government.

Thanks are also due to those within the electric utilities who provided the load survey information which allowed this study to be undertaken, and to many within the Institute who provided graphics, word processing, and editorial assistance.

All tables and graphs displayed in the report and the information contained therein, unless otherwise noted, are the responsibility of the Canadian Energy Research Institute.

The author is solely responsible for the conclusions drawn and for any errors or omissions which are in the report.

Chapter 1

INTRODUCTION

Over the past decade, there has been a dramatic change in the planning environment facing Canadian electric utilities. The growth in demand for electric power has fallen off, become more volatile, and increased the uncertainty of load forecasting. Regulatory pressures have added significantly to the lead times for installing new capacity, further complicating load forecasting uncertainty.

The nature of demand is a complex issue and depends on a number of factors including:

- The Measure of Demand

  The impact of electricity price on demand differs between the demand for power in kilowatts (kW) and energy consumption in kilowatt-hours (kW.h).[1] The demand for power is of particular importance to system planners in determining requirements for plant additions over a utility's planning horizon. Energy consumption impacts are significant in forecasting electricity sales and key financial variables such as revenue and net income.

- Time of Use

  The price sensitivity of customers' electrical demands varies with the specific time at which electricity is used. A kW.h of energy demanded at any given time can be perceived differently from a kW.h demanded at any other time. This perception, in turn, may result in a reduction in energy demand, while not affecting peak use. For example, the purchase of an energy-saving appliance such as a range or refrigerator may alter a household's time duration of electricity use, but not affect its total load during the peak period of the day. The total load shape of the system may also change as energy (the area under the load duration curve) is changed.

- Customer Profile

  There are significant differences in the sectoral composition of total customers across residential, commercial, and industrial classes, and in their energy-using characteristics (e.g., the presence of electricity-intensive industry).

* Planning Horizon

Price sensitivity of electricity demand is a dynamic concept. As the price of electricity relative to other competing fuels increases, consumers may react by reducing energy consumption based on their existing energy-using capital stock (e.g., by turning down the thermostat for electrical heating purposes). If the price change is perceived as sufficiently "permanent," consumers may choose to adjust their capital stock for improved energy efficiency by purchasing, for example, more cost-efficient furnaces. This distinction in price response is termed short-run and long-run price elasticity of demand, respectively.

The purpose of this study is to develop a model which will account for the factors noted ab . and examine their affects on system peak demand.

Specifically, a model is presented which tests the impact of electricity price changes, by sector (e.g., residential, commercial, and industrial), on energy consumption and the demand for power. Assuming no change in customer class load curves, the model is then used to derive a peak load forecast which is consistent with a long-term forecast of customer class energy sales. Finally, the effects of potential load management programs and customer-owned electric power generation in specific sectors are assessed by modifying existing customer class load curves and electricity sales predictions.

1.1 Background

The methodology described in this paper originated with the concept of developing a generic model that would assist in the analysis and forecasting of system peak demand. Forecasting peak, or the maximum demand for a service, is typically linked to industries such as electric power, communications, and transportation services. In these industries, the utility is faced with installing a large amount of capacity that is only required for a very short period of time during the day or year. In order to improve operating efficiency, it is therefore very important for a utility to have an understanding of the composition of peak demand and of the factors which might cause it to change in the future. In this context, for example, many utilities are recognizing that influencing the load patterns of customers, commonly termed load management, can be used to augment operating efficiency and improve system economics.

The peak load forecasting model presented in this paper was developed using load survey information provided by Alberta's electric utilities. This information was readily available and a small, flexible model was seen as an appropriate addition to the existing techniques used to analyze and forecast system peak for Alberta (the Alberta Interconnected System--AIS) by the Electric Utility Planning Council (EUPC).

Within Alberta, the EUPC acts as the body which co-ordinates planning by each utility for a reliable electric energy supply. The EUPC was created in 1972 and is comprised of representatives from the province's seven electric utilities: the Cities of Medicine Hat, Lethbridge, and Red Deer, Edmonton Power, the City of Calgary Electric System and the two investor-owned utilities--Alberta Power Limited and TransAlta Utilities Corporation. The EUPC also includes senior government officials representing the Alberta Departments of Transportation and Utilities, Energy, and Environment who sit as an Advisory Committee on government policy. The following Alberta government organizations sit on the EUPC, in an observer capacity: Alberta Energy Resources Conservation Board, Public Utilities Board, and the Alberta Electric Energy Marketing Agency.

While the EUPC does not itself own or operate any facilities, it does act as the co-ordinating group within Alberta which forecasts future generating and transmission requirements. The EUPC gathers information to help it predict economic trends, areas of growth in the province, and likely industrial development projects. From this, the EUPC annually projects how much electrical energy will be required over the next 25 years. Additional information on the EUPC is contained in Appendix A.

Specific applications for new generation or transmission facilities are made by the individual utilities to the Alberta Energy Resources Conservation Board which assesses the need for, and timing of, the applied-for facilities.

While the model was based upon and tested using data obtained from a number of Alberta electrical utilities, it is important to reiterate that the methodology is applicable to system peak analysis in many capacity-driven industries. In addition, the model might also be readily tailored to forecast peak at the individual utility level.

Footnotes

[1]See Appendix D, Glossary of Terms.

Chapter 2

MODELLING APPROACH

Peak load modelling generally falls under one of four headings: statistical; econometric; end-use; and hybrids. A common approach is to split load data into components (i.e., seasonally adjusted and non-seasonally adjusted; non-weather sensitive and weather sensitive), to use one of these four techniques to model the separate components, and then aggregate to forecast system demand growth.

2.1 Statistical Models

Statistical analyses encompass various time-series techniques which project future values of peak load based on the historical pattern of that demand. Time-series analysis is easy to perform, relatively inexpensive, and provides accurate results when other variables affecting electricity demand are constant or performing in a regular pattern.

The major disadvantage of this technique is its inability to incorporate the interrelationships among the variables which affect the level of system demand. For example, this technique does not account for such factors as relative fuel prices, conservation measures, load management strategies, or changes in economic and engineering variables which may affect the growth of peak load.

2.2 Econometric Models

Econometric models attempt to account explicitly for inter-relationships by incorporating independent variables such as income growth, demographics, industrial activity, and relative fuel prices as proxies for causal relationships between peak load and the determinants of that demand. This approach is relatively uncomplicated and is well suited to long-term forecasting, as it explicitly accounts for expected changes in such factors as economic activity, load mix, and relative prices.

However, the number of explanatory variables included in an econometric equation is limited because high interdependency among the

variables obscures the relative importance of each determinant and the equation's forecasting accuracy. Forecasting load growth is further weakened by the uncertainty introduced by factors such as conservation and load management strategies. Additional uncertainty is also introduced in the forecasting of the explanatory variables themselves.

2.3 End-Use Models

End-use models are essentially a bottom-up approach premised on analyses of the demand patterns of the various subgroups comprising system demand. This technique involves detailed modelling of the causal relationships between electricity demand and related variables in each of the end-use energy or customer class sectors.

Sectoral or end-use analysis offers a number of specific advantages. Load spreading and load reduction strategies can be assessed through model simulations, with energy and demand savings distributed across the end-users (e.g., conservation initiatives) or allocated according to the specific characteristics of the program being analyzed (e.g., load management). End-use models can be extended to: forecasts of load duration curves, as an aid for planning the generation mix; forecasts of "typical" future demand years, as an aid in load management design; and peak demand forecasts, to assist in the design of rate levels. By modelling directly the causal relationships in energy demand, the model clarifies both the reference point of the load forecast and the implications of alternative forecasts.

2.4 Hybrid Models

The majority of recent peak load forecasting research has been devoted to the development of hybrid models, combining an end-use approach with either econometric or statistical analysis. Both top down versions, in which long-term econometric peak load forecasts are allocated across the various end-use categories, and bottom-up versions, in which one or more end-use demand categories are statistically or econometrically forecast and the categories summed to provide a load duration curve or peak load forecast, have been developed.

The objective of a peak load forecasting model should be to utilize all quantifiable factors affecting load growth including conservation, conversion from other fuels, load management, and rate structure change. The modelling of end-use components of peak load allows the explicit assessment of forecast uncertainty arising from

conservation and load management strategies while maintaining consistency among forecasts of energy demand, peak demand, and load shape. The use of econometric or statistical analysis within the end-use models can provide acceptable base load forecasts while decreasing significantly the model size and data requirements.

CERI's peak load forecasting model is such a hybrid version. An outline of the structure is given below and a detailed description is presented in Chapter 3.

2.5 The Methodology

The methodology and computer model developed for this study are designed to perform two major functions:

- quantify changes in electricity sales by customer class as a function of changes in electricity prices; and
- estimate changes in load shape (time pattern of kilowatt demand) for the total system due to changes in electricity prices.

Results are generated for each year within a utility's planning horizon.

The model's electricity sales impact component uses a separate demand equation for each customer class, where electricity sales are assumed to be dependent upon the price of electricity and the level of output or income for each customer class. The functional form of the demand equations is log-linear, which allows the coefficients of each variable to be interpreted as elasticities. The elasticities are measures of the responsiveness of electricity sales to a change in the price or income variables, holding all other exogenous variables fixed.

The demand equations for each customer class are used to generate a "base case" forecast of electricity use under a utility's existing rate structure. Alterations are then made to the rate structure to determine an "impact case" forecast of changes in electricity use. The aggregation of all individual customer class demands yields the impact of a change in electricity prices for the entire electricity system.

The primary task of the load shape component of the model is to simulate how the load (kilowatts) of the entire utility system may be

affected by price changes. This is accomplished by first determining a typical electricity load shape for each customer class. The class load data are derived from load shape samples for individual customers in each class. Estimates of the total electricity system load shape are derived by aggregating these load shapes over all customer classes.

The simulation of system load shape response to price change is accomplished as follows:

- The model uses simulated customer demand data from the sales impact component and the original load shapes for each customer class.
- The customer class load shapes are scaled so that the area under the load curve matches the estimated sales value for any particular year. The model performs this scaling exercise for each customer class and for any specified year using both the "base case" values and the "impact case" values. The output of this component of the model consists of specified load shapes for the base and impact case solutions for all customer classes and for the system total for any specified year.

For any given year, the difference in peak demand between the base case and impact case load shapes indicates the price responsiveness of peak demand in that year.

The data used in estimating energy class load shapes were obtained from sample survey information of individual customer electricity demand measured at 15-minute intervals conducted by Alberta's electric utility companies over the 1982-1986 period. This survey information was then weighted to reflect actual electricity sales for the Alberta Interconnected System (AIS).

The energy sectors analyzed are listed below.

1. Residential
2. Farm
3. Commercial
4. Street Lighting
5. Urban Transit
6. Pipeline Transportation
7. Oil Fields
8. Oil Sands
9. Oil Refineries
10. Gas Plants

11. Gas Reprocessing
12. Chemicals
13. Coal
14. Cement
15. Forest Products
16. Other Industrial

Chapter 3

MODEL OVERVIEW

Customer reaction to a change in electricity rates will normally take two forms. First, the customer may change the amount of electric energy consumed. Second, if there is any price incentive to do so, the customer may change the timing of electrical energy consumption.

The extent to which a customer reacts to a rate change varies among and within various customer groups. The aggregation of response over all individual customers impacts on the two major consumption statistics of an electricity system. These are energy sales, measured in kilowatt hours, and the rate of use of energy over a given time period, called load or demand and measured in kilowatts. These two factors are important for both system planning and operation. An electric utility must be able to meet the energy requirements over any given time period and any instantaneous load fluctuations. To the extent that changes in rate structure impact on system sales and load, it is important to be able to accurately estimate what these impacts could be.

This chapter contains a detailed description of the model used to estimate customer reactions to a change in electricity prices. The model consists of two major components: the electricity sales component, which quantifies the change in sales by customer class due to an electric power rate (price) change; and the load shape component, which establishes the changes in load shapes for the total system. These results are generated for each year within the planning horizon.

3.1 Electricity Sales Impact Component

The electricity sales component of the model estimates electricity sales by customer class under alternative pricing assumptions.

3.1.1 Structure

The model has a separate electricity demand equation for each of the sixteen customer classes. Each demand equation includes electricity price and an output or income variable, all of which are measured in real or constant dollar terms.

3.1.2 Assumptions

In order to operate the model, assumptions must be made for several important elements.

- The number of individual customer classes for demand estimation must be specified. The greater the degree of disaggregation, the less generalization is required when estimating the impact of price changes. Most studies of electricity demand utilize only three customer classes: residential, commercial, and industrial. While this breakdown may be acceptable for more general purposes, the specific nature of rate structure change and the large differences in expected customer reaction normally require further disaggregation of demand.

- In order to use the impact model to forecast future levels of electricity demand, it is necessary to have historical data (for the endogenous and exogenous) variables and estimates of the equation parameters. The "endogenous" variables comprise the customer class energy sales data, the "exogenous" variables are the price and output data, and the equation parameters are the price and output elasticities.

- To operate the model, electricity price data are required. There must be an electricity price (measured in cents/kW.h) for every pricing period in every customer class.

3.1.3 Simulation Framework

The method of measuring the impact of a price change is as follows. The demand equations for each customer class are used to generate a "base case" forecast of electricity use under the existing rate structure. Alterations are then made to electricity prices by customer class to replace the existing rates. Using the same structure for the demand equations along with these new prices, an "impact case" forecast of electricity is generated.

3.2 Customer Load Shape Component

This component of the impact model fulfills two tasks. The first is the determination of energy sales by period for each customer class. The second is to simulate how the load on the entire utility system can be affected by rate structure changes.

3.2.1 Derivation of Customer Load Shapes

The first requirement is for a typical load shape for every customer class. This is done using a sample of individual customer load data. The class load shape is then determined by adding across customer samples for each hour.

3.2.2 Scaling Class Load Shapes to Equal Total Sales Figures

Because the class load curves are derived from a sample of customers, they must be scaled to be consistent with total class sales. The scale factor is total class sales for any given time period divided by the total sales of the sample customers for the same time period. This scale factor is applied to all the hour-by-hour kilowatt values of the load shape to "fit" the total class sales underneath the load curve.

3.2.3 The System Load Shape and Model Operation

Estimates of the total system load shape are derived by aggregating the corresponding load shapes over all customer classes. The next task of the load shape component of the model is to simulate how Total System Load is affected by electricity price changes.

- The model uses as inputs the simulated customer demand data from the sales impact component (both the "base case" and "impact case" values) and the original load shapes for each customer class.

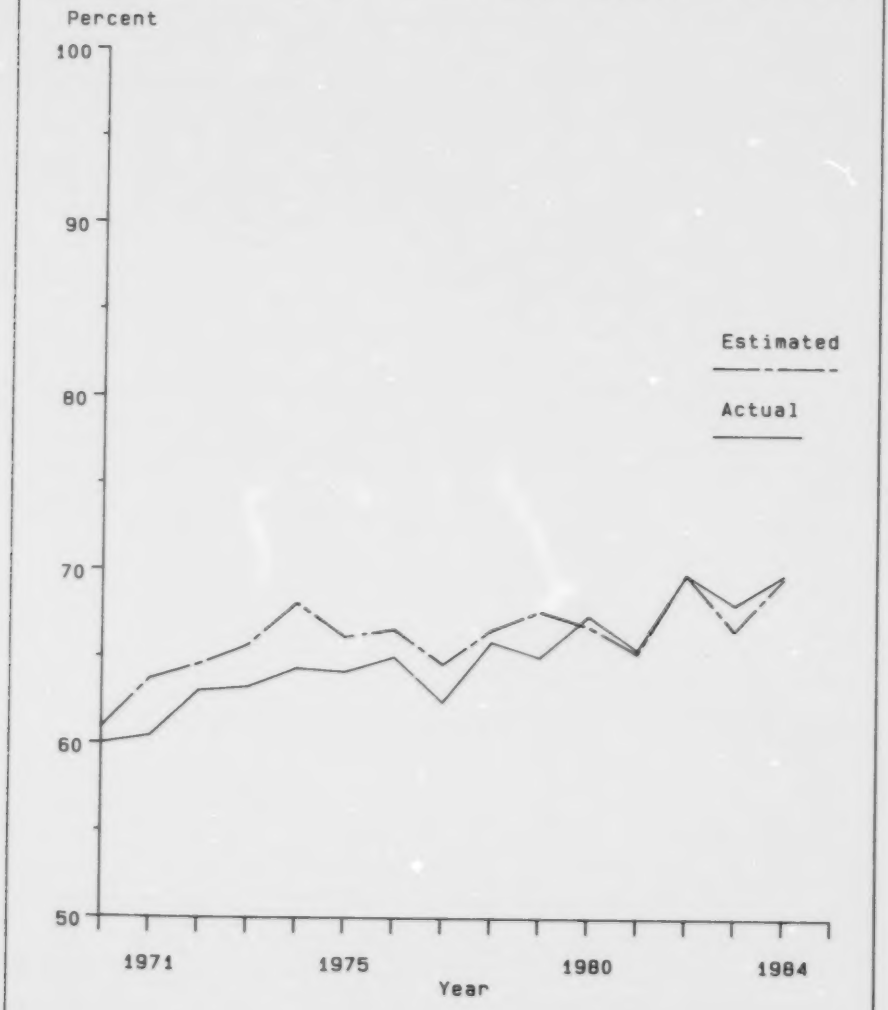
- The class load shape periods are scaled so that the area under the load curve matches the simulated sales value for any particular year. The model performs this scaling exercise for each customer class, and for any specified year of the forecast, using both the "base case" values and the "impact case" values. Implicit in this procedure is the assumption that the shape of the original load

TABLE 3.1

COMPARISON OF ACTUAL LOAD FACTOR
VERSUS MODEL SIMULATIONS

	AIS Actual System Load Factor (%)	Model Simulations on Actual Data (%)	Actual Less Simulation
1970	60.11	60.95	-0.0084
1971	60.61	63.84	-0.0323
1972	63.13	64.64	-0.0151
1973	63.33	65.84	-0.0251
1974	64.41	68.20	-0.0379
1975	64.22	66.25	-0.0203
1976	65.07	66.66	-0.0159
1977	62.49	64.77	-0.0228
1978	66.08	66.59	-0.0051
1979	65.19	67.69	-0.0250
1980	67.44	66.83	0.0061
1981	65.44	65.32	0.0012
1982	69.83	69.95	-0.0012
1983	68.23	66.69	0.0154
1984	69.93	69.77	0.0016

FIGURE 3.1
ESTIMATED VS. ACTUAL LOAD FACTOR



curves for each customer class remain unaltered over all the hours in each year.

- The output of this component of the model consists of specified load shapes for the base and impact case solutions, for all customer classes, and for the system total for any specified year.[1]

The model has been developed to run interactively in a Lotus 1-2-3 simulation environment.[2]

3.2.4 Model Accuracy

To test the accuracy of the model, it was simulated from 1970 to 1984 and compared to actual AIS load data for this period. Table 3.1 and Figure 3.1 show model estimates and actual load factors for the AIS, indicating that the estimation accuracy of the model was generally good, particularly in the 1980-1984 period.

While the results appear to indicate some room for moderate improvement in the model's predictive capabilities, it appears sufficiently refined to assess system impacts of changes in price levels and particularly for forecasting system peak demand under various assumptions about load management and customer-owned electric generation.

Footnotes

[1]The preceding overview was abstracted from: Gerard J. Protti and Robert N. McRae, The Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited. CERI Study No. 10 (Calgary: Canadian Energy Research Institute, April 1980).

[2]Lotus and 1-2-3 are registered trademarks of Lotus Development Corporation.

Chapter 4

MODEL RESULTS

4.1 Price Response

As noted in Section 3.1, the first task is to estimate a set of equations which are descriptive of electric energy sales for the sixteen different customer classes. An "impact" or real annual increase in the historic level of electricity prices is then input to these equations, holding other factors constant, and incremental electricity sales resulting from the change in price are calculated. The sum of price induced effects across all customer classes yields a total system response to the change in the price of electricity.

The actual and "base case" or econometric estimates of electricity sales, holding prices constant at their historic level, are shown in Table B.1 of Appendix B. The econometric estimates of electricity sales underestimate actual sales for the AIS by only 1525 GW.h or 0.6 percent over the entire 1970-1984 period. Table B.2, Appendix B, displays the base case together with the results of a 5 and 10 percent change in real electricity prices for all sixteen sales categories. An annual 5 percent real increase over the historic prices of electricity causes total AIS electricity sales to fall from 240 381 GW.h for the base case to 236 813 GW.h, or only 1.5 percent. A 10 percent real increase over historic price levels causes total 1970-1984 period sales to drop to 233 244 GW.h for a percentage fall relative to the base case of only 3 percent. While some customer classes are notably more price responsive than these figures indicate, electricity sales in aggregate were rather unresponsive to real increases in the price of electricity over the 1970-1984 period.

The results of taking the econometric sales estimates depicted in Table B.2, Appendix B, and applying them to the peak load forecasting model are shown in Figure 4.1 and Table 4.1. As expected, the drop in system load factor for both a 5 and 10 percent real annual increase in the price of electricity was negligible. In effect, the model results indicate that a 10 percent increase in electricity prices would have resulted in an average fall in system load factor of only some 0.85 percent for the 15-year period, 1970-1984.

FIGURE 4.1
ESTIMATED SYSTEM LOAD FACTOR

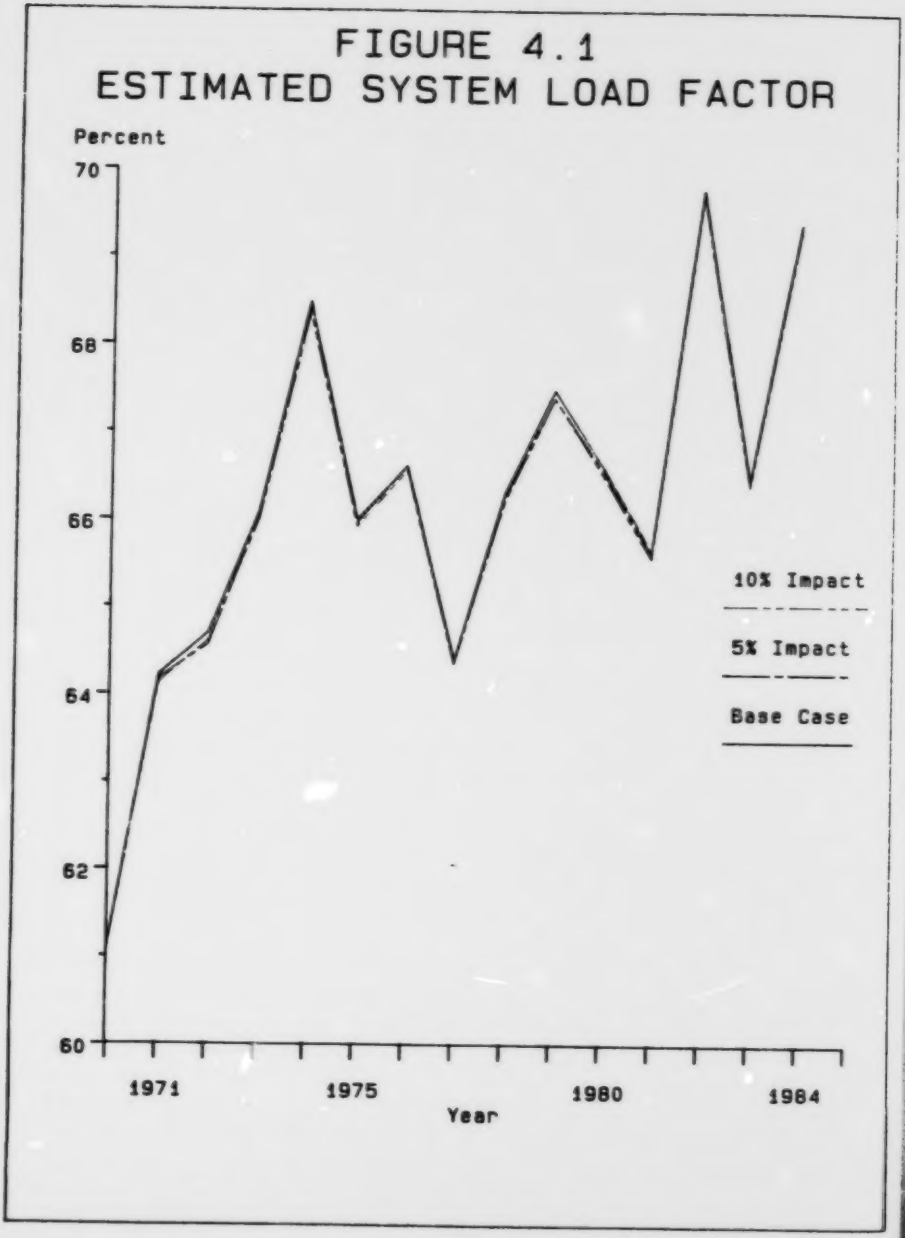


TABLE 4.1

COMPARISON OF MODEL SIMULATIONS
OF SYSTEM LOAD FACTOR

	5 Percent Impact Case			10 Percent Impact Case	
Year (1)	Base Case (2)	Impact Case (3)	Base-Impact (4)	Impact (5)	Base-Impact (6)
1970	61.12	61.09	0.0003	61.06	0.0006
1971	64.22	64.18	0.0004	64.15	0.0007
1972	64.71	64.60	0.0011	64.64	0.0007
1973	66.11	66.06	0.0005	66.02	0.0009
1974	68.49	68.44	0.0005	68.39	0.0010
1975	66.03	65.99	0.0004	65.95	0.0008
1976	66.65	66.61	0.0004	66.57	0.0008
1977	64.43	64.39	0.0004	64.35	0.0008
1978	66.32	66.28	0.0004	66.23	0.0009
1979	67.52	67.40	0.0012	67.42	0.0010
1980	66.62	66.58	0.0004	66.53	0.0009
1981	65.67	65.63	0.0004	65.58	0.0009
1982	69.81	69.77	0.0004	69.73	0.0008
1983	66.49	66.44	0.0005	66.40	0.0009
1984	69.42	69.37	0.0005	69.32	0.0010

4.2 Energy and Load Forecasting

To further evaluate the performance of the peak load forecasting model, a number of simulations were undertaken using the EUPC's latest long-term forecast of Alberta's electric energy requirements.[1] The EUPC annually prepares a 25-year forecast of energy and peak demand which uses a combination of econometric and end-use forecasting techniques together with market survey information. The use of the EUPC electric energy sales forecasts in CERI's load forecasting model, therefore, allowed a direct comparison of the EUPC estimates with the CERI estimates of system peak demand and load factor. In recognition of the many forecast uncertainties associated with recent oil and gas price volatility, the EUPC presented four separate electrical forecasts in its 1986 publication. For the purposes of this comparison, the EUPC's "low for 3 years" scenario was used as the basis for simulating the CERI load shape model.

In the first simulation, the 15-year averages (1970-1984) of December peak to annual peak and December sales to annual sales of 0.9873 and 0.0986, respectively, were used to simulate the CERI peak load forecasting model. Given forecasts of customer class energy sales, these ratios are required as model input in order to simulate demand for a typical winter peak day. The ratio 0.9873 is an average of December peak to actual system peak for the 1970-1984 period, indicating that December, on average, represented 98.7 percent of actual peak over this period. The average ratio of December energy sales to total annual sales for the 1970-1984 period was 9.86 percent.

As shown in Table 4.2 and Figures 4.2 and 4.3, there is a significant difference in the EUPC and CERI estimates of peak demand and load factor. While using average peak demand and peak sales values for the last 15 years is admittedly a judgment call in forecasting when peak is likely to occur in future years, it is nevertheless representative of what has occurred.

The second case depicts a more realistic planning case where peak is assumed to occur in December and December energy sales are held at their 15-year average of 9.86 percent of annual sales. As shown in Table 4.3, CERI and EUPC forecasts of demand are moderately closer than those displayed in Table 4.2 and the 1985 simulated load factor closer to the actual of 70 percent.

TABLE 4.2

COMPARISON OF EUPC FORECAST WITH PEAK LOAD MODEL

Year	EUPC Demand (MW)	EUPC Load Factor (%)	Model Demand	Model Load Factor (%)
1985	4954.4	70.0	5160.2	67.21
1986	5174.6	70.5	5404.4	67.55
1987	5371.3	70.9	5616.7	67.83
1988	5522.8	71.3	5788.9	68.01
1989	5630.5	71.6	5932.4	67.96
1990	5727.4	71.7	6041.9	68.00
1991	5860.6	71.8	6188.2	68.01
1992	6134.4	72.3	6459.8	68.71
1993	6406.0	72.7	6750.1	69.01
1994	6768.8	73.2	7120.5	69.58
1995	7039.9	73.4	7418.1	69.67
1996	7321.1	73.5	7678.0	70.08
1997	7542.9	73.4	7898.8	70.05
1998	7749.0	73.4	8120.9	70.03
1999	8008.1	73.4	8384.1	70.07
2000	8250.4	73.3	8630.6	70.06

NOTE: Assumes 1970-1984 average ratios of December peak to annual peak and December sales to annual sales.

FIGURE 4.2
ESTIMATED PEAK LOAD

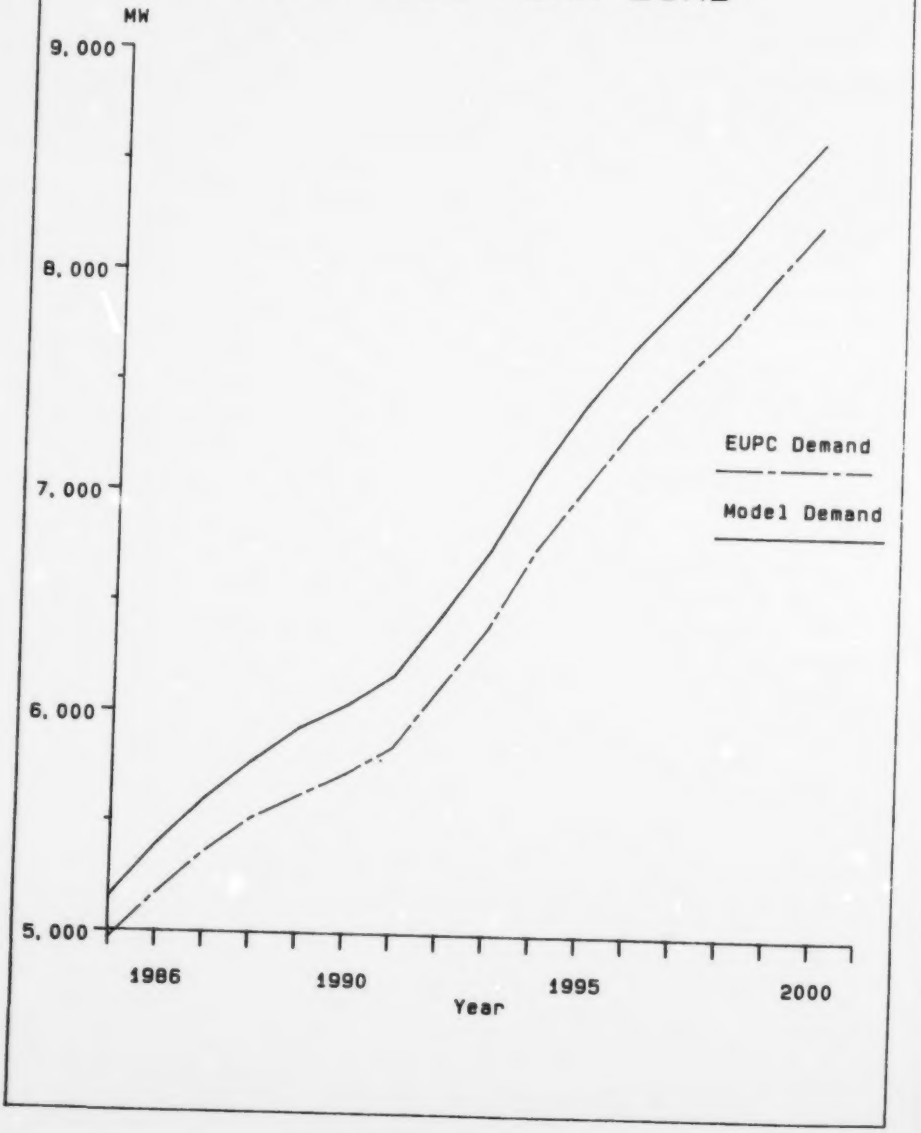


FIGURE 4.3
ESTIMATED LOAD FACTOR

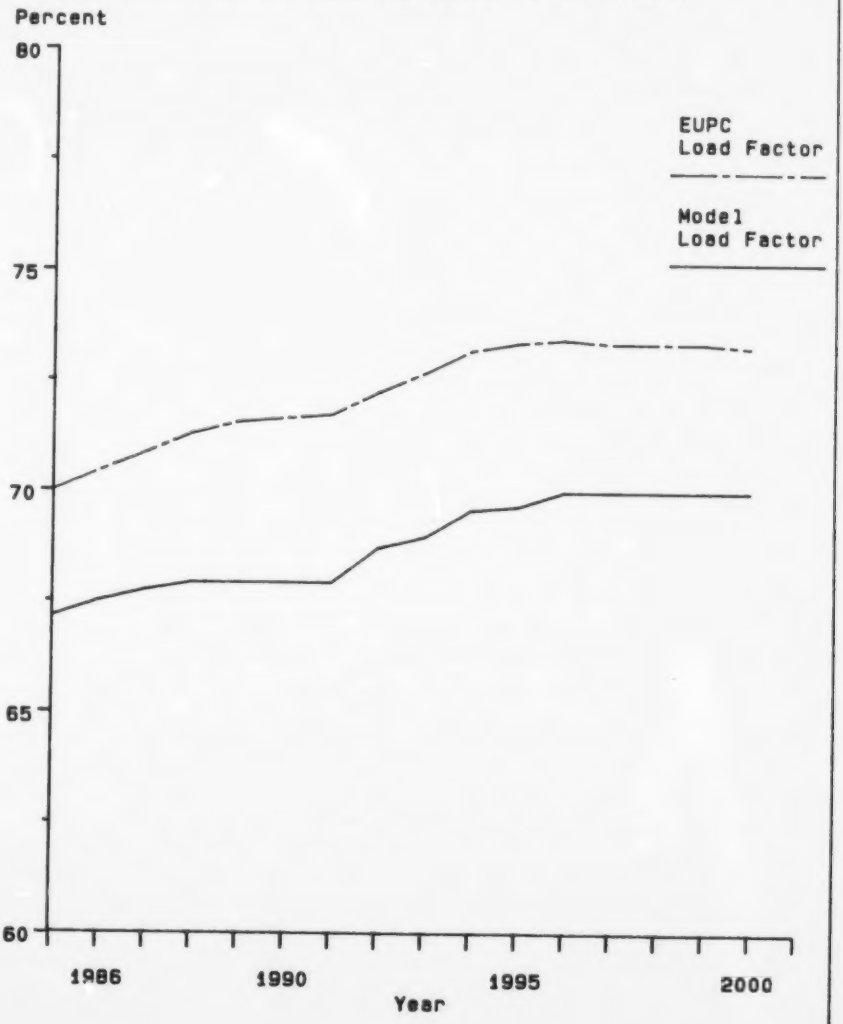


TABLE 4.3

COMPARISON OF EUPC FORECAST WITH PEAK LOAD MODEL

Year	EUPC Demand (MW)	EUPC Load Factor (%)	Model Demand	Model Load Factor (%)
1985	4954.4	70.0	5094.7	68.08
1986	5174.6	70.5	5335.8	68.41
1987	5371.3	70.9	5545.4	68.71
1988	5522.8	71.3	5715.4	68.89
1989	5630.5	71.6	5857.1	68.84
1990	5727.4	71.7	5965.2	68.88
1991	5860.6	71.8	6109.6	68.88
1992	6134.4	72.3	6377.7	69.59
1993	6406.0	72.7	6664.4	69.90
1994	6768.8	73.2	7030.1	70.48
1995	7039.9	73.4	7323.8	70.56
1996	7321.1	73.5	7580.4	70.98
1997	7542.9	73.4	7798.5	70.95
1998	7749.0	73.4	8017.8	70.93
1999	8008.1	73.4	8277.6	70.97
2000	8250.4	73.3	8521.0	70.96

NOTE: Assumes 1970-1984 average ratio of December sales to annual sales and peak occurring in December.

In order for CERI estimates of system load to closely match the EUPC forecasts, the CERI model was tuned so as to back out the implicit EUPC ratio of December energy sales relative to annual sales. This resulted in a ratio of December sales to total annual sales of 9.49 percent. The forecast comparisons for this simulation are shown in Table 4.4 and Figures 4.4 and 4.5. The effect of simply lowering the December ratio of electricity sales from 0.986 to 0.0949, while assuming that peak will occur in December, is significant--the EUPC and CERI estimates of system load are virtually identical.

As noted above, the actual average ratio of December sales to total annual sales for the 1970-1984 period was 9.86 percent. Moreover, over the entire 1961-1984 period, there were only 3 years where this ratio was less than the EUPC's implicit forecast ratio of 9.49 percent. While the appropriate factor is of course a judgment call, it seems more realistic to use a ratio which is based on actual experience over the past 10 or so years. In this context, the implicit EUPC ratio appears low and some further analysis should be undertaken. Additional study is warranted as the CERI model forecast assumes that the underlying load curves are constant over time. The EUPC, conversely, assumes that the total system load factor will increase as the result of the continued trend toward load management. While it seems unlikely that this assumption would account entirely for the forecast differences, a definitive answer can only be obtained by simulating EUPC forecasts of changes in end-use load curves using the CERI peak load forecasting model.

4.3 Customer-Owned Generation

The results described below present an application where CERI's peak load forecasting model is used to evaluate the effects of customer-owned electrical generation on AIS system peak. Cogeneration is one form of customer-owned generation which has been receiving increased interest of late in North America. Cogeneration is the simultaneous production of electric power and useful thermal energy in one technological process. An industrial cogeneration facility supplies thermal energy (steam) to the production process and electricity to meet a portion or all of a company's plant requirements. In some cases, the cogenerator may also provide surplus electric power to the utility grid.[2]

TABLE 4.4

COMPARISON OF EUPC FORECAST WITH PEAK LOAD MODEL

Year	EUPC Demand (MW)	EUPC Load Factor (%)	Model Demand	Model Load Factor (%)
1985	4954.4	70.0	4954.4	70.00
1986	5174.6	70.5	5133.0	71.12
1987	5371.3	70.9	5334.6	71.42
1988	5522.8	71.3	5498.1	71.61
1989	5630.5	71.6	5634.4	71.56
1990	5727.4	71.7	5738.5	71.60
1991	5860.6	71.8	5877.4	71.61
1992	6134.4	72.3	6135.3	72.34
1993	6406.0	72.7	6411.1	72.66
1994	6768.8	73.2	6762.9	73.26
1995	7039.9	73.4	7045.4	73.35
1996	7321.1	73.5	7292.3	73.79
1997	7542.9	73.4	7502.1	73.75
1998	7749.0	73.4	7713.0	73.73
1999	8008.1	73.4	7963.0	73.77
2000	8250.4	73.3	8197.1	73.76

NOTE: Assumes peak occurs in December and uses December sales to annual sales ratio of 0.0949.

FIGURE 4.4
ESTIMATED PEAK LOAD

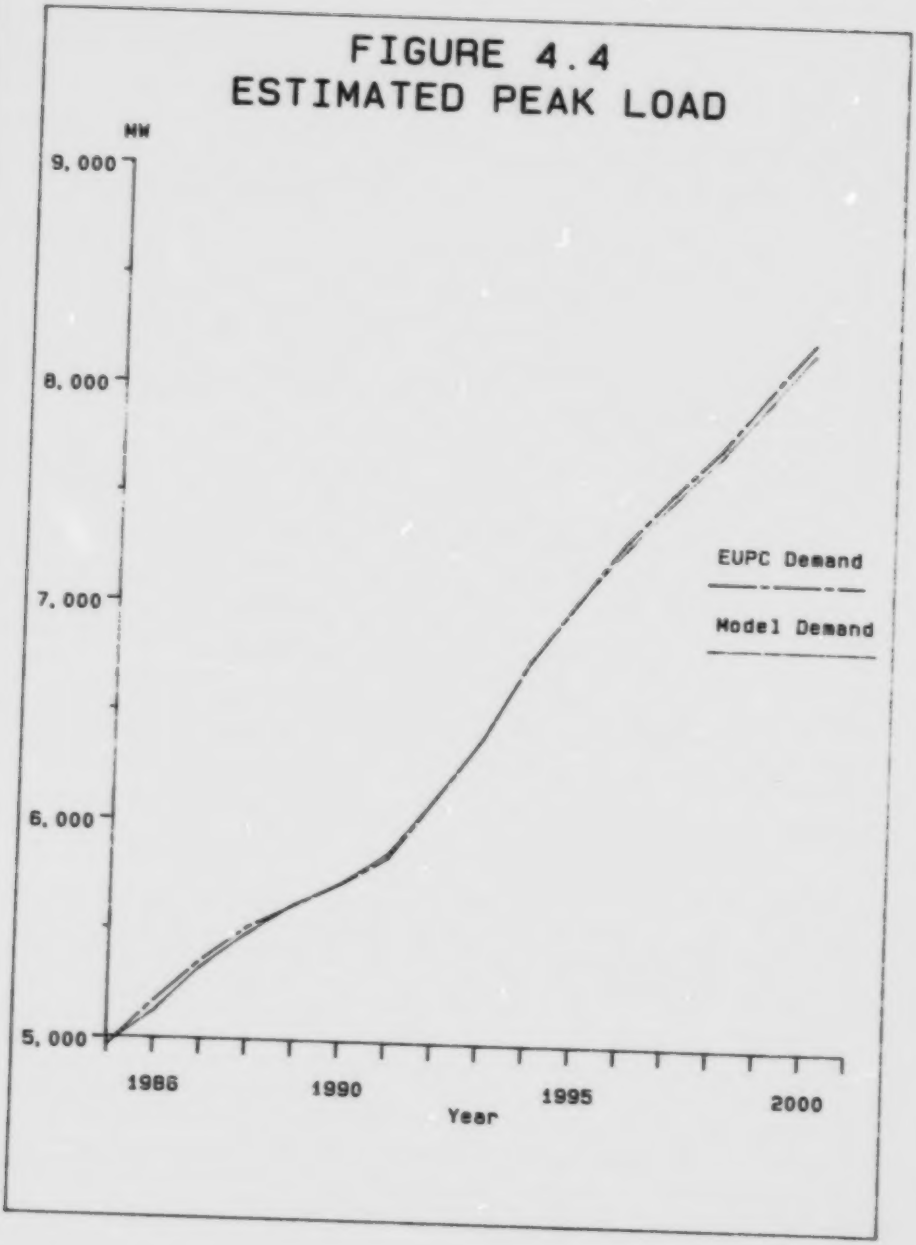
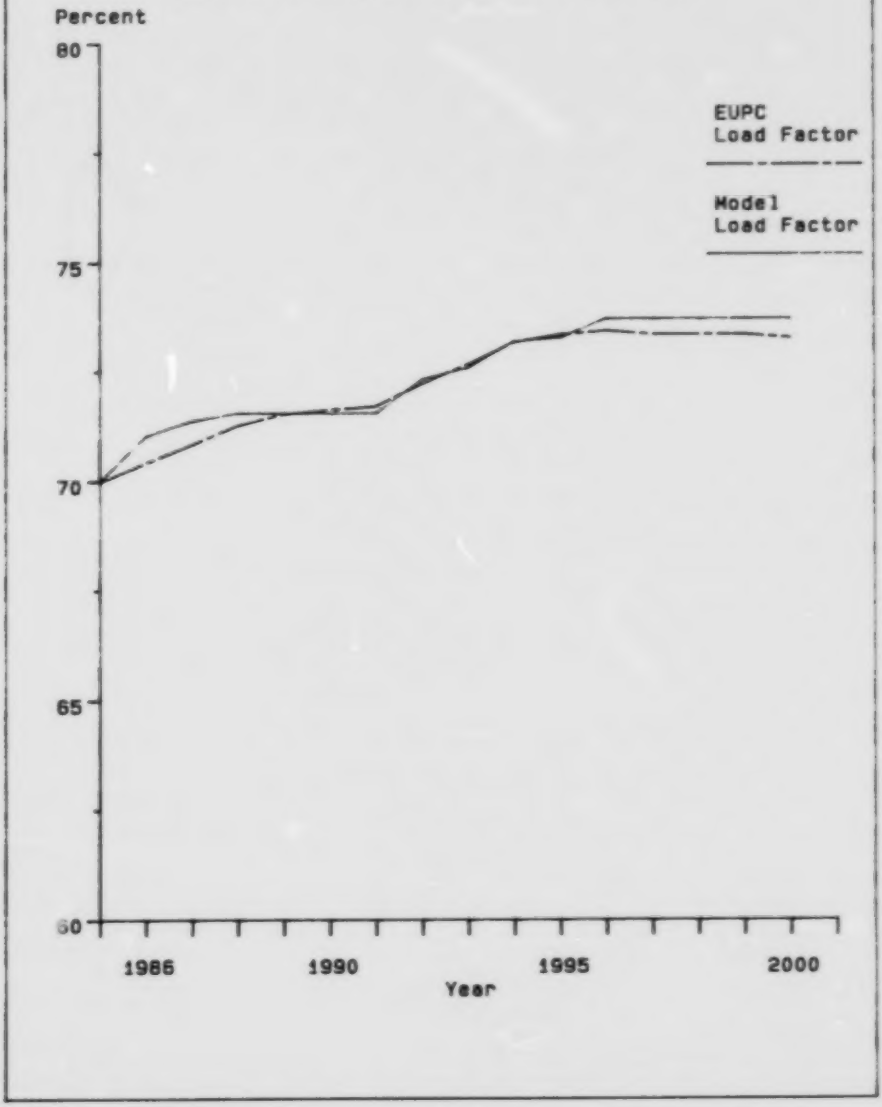


FIGURE 4.5
ESTIMATED LOAD FACTOR



In order to isolate those customers likely to generate their own electricity requirements, end-use customer classes were ranked by their degree of electrical price responsiveness alongside their relative consumption of electricity for the year 1984. The results are shown in Table 4.5. The degree of price responsiveness was based upon the econometric equations determined for each end-use class for the 1961-1984 period (see Table B.2, Appendix B).

As shown in Table 4.5, gas plants and gas reprocessing facilities are end-use classes where customer-owned electricity generation might likely be installed. These end-use customers are responsive to changes in the price of electricity, account for a proportionately large share of total electricity sales, and have high load factors (see Appendix C, Model Simulation of Normalized Load Shapes (1986) for Selected Sales Categories).

It should be noted that financial criteria are not the only factors which will determine the actual decision with respect to customer-owned investment. Even for a relatively energy-intensive industry, customer-owned generation may be assigned a low priority compared, for example, to plant expansion or other plant improvements. Expenditures on customer-owned generation may be perceived as secondary to the primary business of product manufacturing. In general, the decision whether or not to invest could depend on various considerations, including financial soundness, capital constraints, competing investments, and management attitudes. While the decision to generate one's own electric power is then dependent upon many factors, gas plants and gas reprocessing facilities seem to share a number of those characteristics which could make them likely candidates for customer-owned electricity generation.

Table 4.6 and Figure 4.6 show a CERI model simulation of a hypothetical case where the EUPC's electricity sales forecasts for gas plants and gas reprocessing facilities is reduced by 50 percent over the 1990-2000 period, to account for on-site customer-owned electricity generation. The case entitled "without customer-owned generation" shows the CERI model predictions of demand assuming the EUPC implicit December forecast sales ratio of 0.0949. This case was used to ensure a consistent comparison between the EUPC load forecast and CERI Model estimates of peak resulting from customer-owned generation. As shown in Table 4.6, the use of customer-owned generation starting in 1990 for gas plants and gas reprocessing facilities only causes the average system load factor over the 1990-2000 period to drop from 73.06 to

TABLE 4.5

RANKING OF END-USE CLASSES BY PRICE RESPONSIVENESS
AND ENERGY CONSUMPTION

End-Use Class	Ranked By Price Responsiveness[a]	Ranked by Consumption[b]
Gas Reprocessing	1	8
Gas Plants	2	6
Forestry	3	15
Oil Sands	4	12
Pipelines	5	10
Urban Transit	6	16
Oil Fields	7	4
Oil Refineries	8	9
Residential	9	2
Street Lighting	10	13
Other Industrial	11	5
Petrochemical	12	3
Coal	13	11
Farm	14	7
Commercial	15	1
Cement	16	14

[a]Based on econometric estimates for the 1961-1984 period.
[b]Based on percent of 1984 total energy sales.

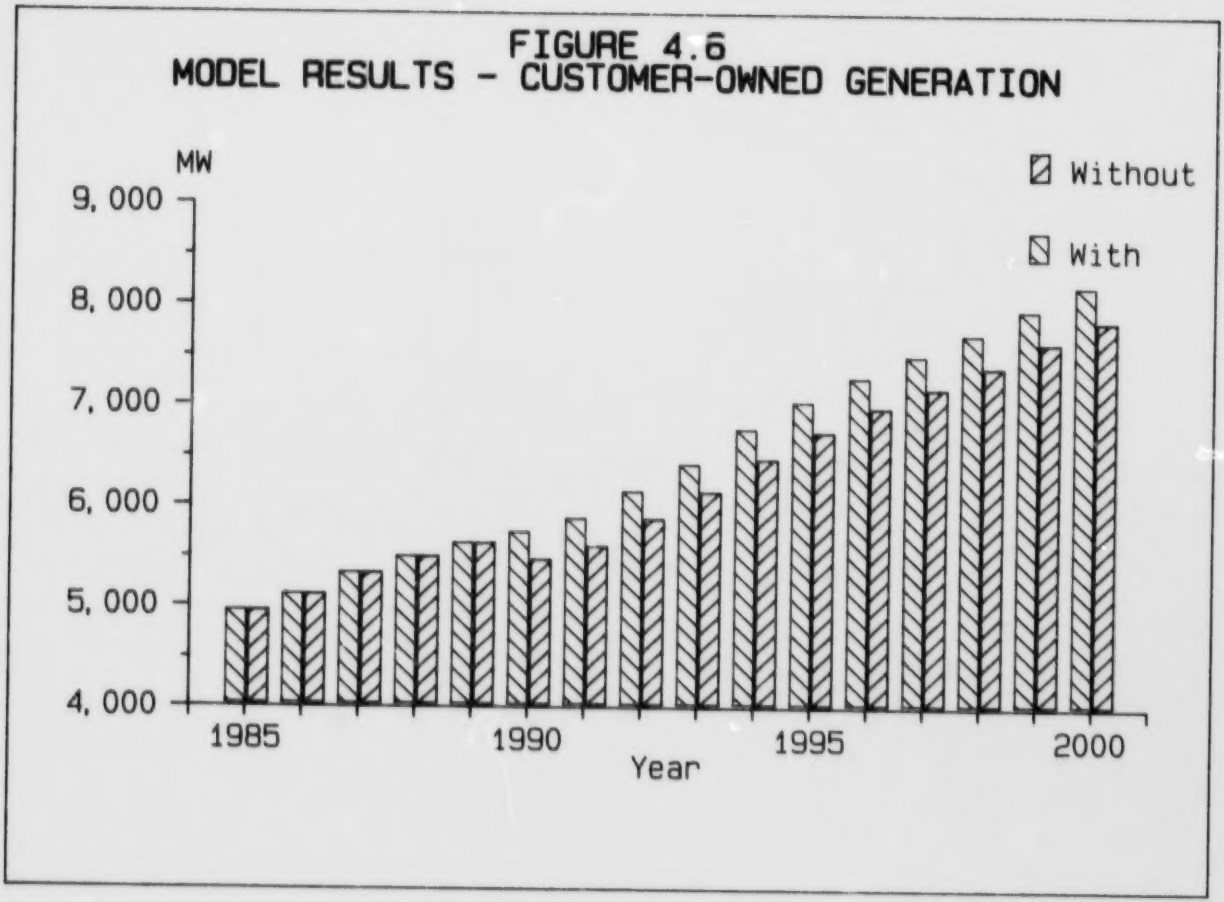
TABLE 4.6

COMPARISON OF FORECAST MODEL RESULTS:
CUSTOMER-OWNED GENERATION

Year	Without Customer-Owned Generation		With Customer-Owned Generation	
	Demand (MW)	Load Factor (%)	Demand (MW)	Load Factor (%)
1990	5738.5	71.60	5480.9	70.66
1991	5877.4	71.61	5615.9	70.67
1992	6135.3	72.34	5868.4	71.47
1993	6411.1	72.66	6136.0	71.82
1994	6762.9	73.26	6477.1	72.46
1995	7045.4	73.35	6749.8	72.56
1996	7292.3	73.79	6987.3	73.02
1997	7502.1	73.75	7187.1	72.98
1998	7713.0	73.73	7387.7	72.95
1999	7963.0	73.77	7624.3	72.99
2000	8197.1	73.76	7843.4	72.96
11-Year Average	6967.1	73.06	6668.9	72.20

NOTE: Assumes a 50 percent reduction in EUPC forecast energy sales for gas plants and gas reprocessing plants over the 1990-2000 period.

FIGURE 4.6
MODEL RESULTS - CUSTOMER-OWNED GENERATION



72.20 percent. A fall of 50 percent in predicted electricity sales in just these two industries translates to a drop in peak demand of just over 350 MW by the year 2000, necessitating the delay in the on-stream date of one AIS thermal generating station.

While AIS plant additions are delayed under this hypothetical scenario, the system load factor is not materially affected. The drop in load factor, as shown in Table 4.6, falls in the year 2000 to only 73 percent with customer-owned generation relative to 73.8 percent without customer-owned generation.

In conclusion, while the above is a hypothetical example of system affects resulting from an assumption about future customer-owned generation, it does point to the model's capabilities for various, more refined scenario analyses. A detailed survey and evaluation of the potential market for customer-owned electricity generation in Alberta would be required as input to the CERI load forecasting model. Various scenarios might then be evaluated where different levels of market penetration for customer-owned generation were assumed and the model simulated to quickly evaluate probable system-wide affects.

4.4 Load Management

The final simulations of the CERI peak-load forecasting model were used to evaluate the system-wide affects of a hypothetical load management program.

Load management may be defined as any activity by an electric utility which alters the size and characteristics of the load, thereby producing economic benefits to the utility. Under this broad heading are several programs in which utilities are currently engaged:

(a) direct control of loads from a central point or station;

(b) alternative energy sources such as the use of dual-energy systems or cogeneration;

(c) energy efficient home designs;

(d) energy recovery systems which use rejected heat streams;

(e) efficiency standards for appliances and equipment;

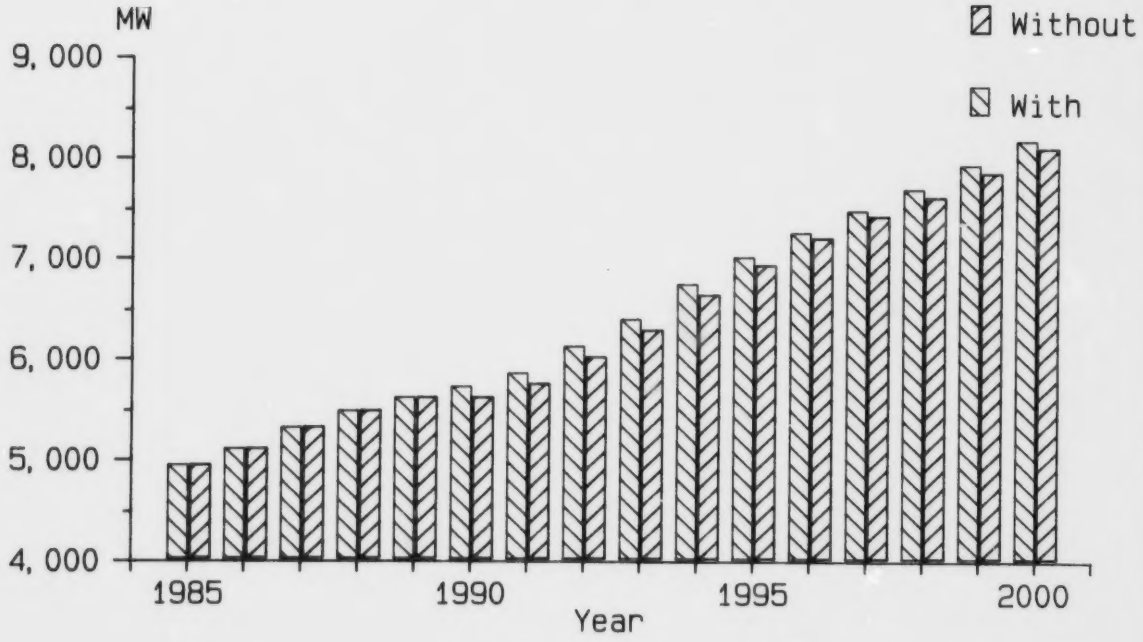
TABLE 4.7

COMPARISON OF FORECAST MODEL RESULTS:
LOAD MANAGEMENT

Year	Without Load Management		With Load Management	
	Demand (MW)	Load Factor (%)	Demand (MW)	Load Factor (%)
1990	5738.5	71.60	5646.0	72.77
1991	5877.4	71.61	5782.5	72.78
1992	6135.3	72.34	6035.9	73.53
1993	6411.1	72.66	6308.9	73.83
1994	6762.9	73.26	6672.6	74.26
1995	7045.4	73.35	6950.1	74.36
1996	7292.3	73.79	7235.5	74.36
1997	7502.1	73.75	7438.9	74.38
1998	7713.0	73.73	7642.0	74.41
1999	7963.0	73.77	7885.2	74.50
2000	8197.1	73.76	8111.1	74.54
11-Year Average	6967.1	73.06	6882.6	73.97

NOTE: Assumes a shift of 2 percent of normalized load from 1800 hours to 1900 and 2000 hours for coal, commercial, farming, urban transit, residential and other industrial sectors.

FIGURE 4.7
MODEL RESULTS - LOAD MANAGEMENT



(f) energy information programs which promote conservation of energy; and

(g) changes in rate structure design and incentives.[3]

As in the previous example, the model simulations presented in Table 4.7 and Figure 4.7 assume the implicit EUPC December sales ratio of 0.0949. As noted previously, this permits a more direct comparison between CERI model results and EUPC long-term forecasts of AIS peak demand. The results presented here assume that Alberta's electric utilities introduce programs which result in a small shift in load from system peak use at 6:00 p.m. for the coal, commercial, farming, urban transit, residential, and other industrial sectors. For the purposes of this simulation, 2 percent of the respective normalized load at system peak for these end-use classes is shifted equally from 6:00 p.m. to 7:00 p.m. and 8:00 p.m. for the 1990-2000 period.

As shown in Table 4.7, the average system load factor over the 1990-2000 period improves by just under 1 percent and estimated system peak in the year 2000 falls moderately to 8111 MW from 8197 MW without the load management program. System peak over the 1990-2000 period falls from an estimated average of 6967 MW to 6883 MW or 1.2 percent for the period.

The results of this example again indicate the ability of the model to quickly assess the system-wide effects of various load management scenarios. The model also provides utilities with a sound analytical method for evaluating the benefits of improved system load factor relative to the expected costs of a given load management program. Alternatively, a system load factor could be predetermined, and changes could then be made to specific end-use load curves to simulate this result. The system benefits of load factor improvement might then be assessed against the expected cost of instituting the load management programs required to modify the load curves of specific end-use classes.

Footnotes

[1]Alberta Electric Utility Planning Council, 1986 EUPC Forecasts of Alberta's Electric Energy Requirements 1986 to 2010, September 9, 1986.

[2]Anthony E. Reinsch and Ellen F. Battle, Industrial Cogeneration In Canada: Prospects and Perspectives, CERI Study No. 24 (Calgary: Canadian Energy Research Institute, March 1987).

[3]A. Juchymenko, Status of Load Management, report prepared by Cogeneration Associations Limited for the Canadian Electrical Association, Contract No. 170 D 287 (Montreal: Canadian Electrical Association, August 1983), p. (1).

Chapter 5

CONCLUSIONS

5.1 Conclusions

This study has provided a general overview of a small but very flexible model developed by the Canadian Energy Research Institute. The model was applied to forecasting peak and system load factors for the Alberta Interconnected System. The essential feature of this model is the derivation of an hourly load curve for a cold winter day during the peak month by end-use sector. As noted in a recent survey of peak demand forecasting techniques for the Canadian Electrical Association, one of the most promising techniques would be to include some integration of load shape analysis into energy forecasts on a sectoral basis.[1] The forecasting model outlined in this paper is just such a hybrid version.

The model was used to evaluate the impact of electricity price changes by sector on energy consumption and the resulting demand for power. Using hypothetical cases for customer-owned generation and load management, the model was also used to assess the system-wide effects of these programs. A comparison of CERI and EUPC forecasts of Alberta electricity demand was also made and suggestions outlined for further study of the discrepancies between the results.

The evaluation of the impact of price changes concluded that AIS electricity sales and system peak are rather unresponsive to a change in the price of electricity. Model results indicate that a 10 percent increase in real electricity prices would have resulted in a drop in electricity sales of only 3 percent over the entire 1970-1984 period; the average system load factor would have fallen only 0.85 percent. We might conclude from these results that a move to peak and off-peak pricing would appear to have little impact on electricity sales but could improve the system load factor.

The assumption of a 50 percent drop in forecast energy sales in gas plants and gas reprocessing facilities (1990-2000), due to the installation of customer-owned generating facilities, had a significant impact on peak demand but did not not materially affect the system load factor. Estimated peak demand fell by just over 350 MW by the year

2000, but the system load factor dropped to only 73 percent "with" customer-owned generation compared to a predicted 73.8 percent for the "without" customer-owned generation case.

Finally, the model was applied to a case where load management programs were assumed to cause a small shift in load from system peak at 6:00 p.m. in the coal, commercial, farming, urban transit, residential, and other industrial sectors. A 2 percent shift in load for these end-use classes over the 1990-2000 period results in an improvement of just under 1 percent in the average system load factor for the period and a consequent, but modest, fall in system peak demand.

5.2 Potential Model Applications

As noted in this report, CERI's peak load forecasting model offers a number of rather robust analytical capabilities. The energy forecasting component can be used to forecast a "base case" scenario for future energy sales. This forecast could be revised to include predicted changes in energy consumption per unit of output, industrial expansion plans, etc. The load shape component could then be used to forecast system peak and load factor assuming no changes in the underlying sectoral load curves. At this juncture, various scenarios might then be evaluated such as: potential load management programs, prospective customer-owned generation, and peak and off-peak pricing implications in various end-use classes. The result would be a consistent set of forecasts of energy and peak demand.

It is also important to emphasize the model's evaluation capabilities. The model readily permits, for example, a method of analyzing the costs and benefits of various load management programs in the context of a forecast of changing load mix.

While the model was based upon and tested using survey data of 15-minute load readings from Alberta's electric utilities, the methodology outlined in this paper is applicable to system peak analyses in other jurisdictions and in other capacity-driven industries. The model can easily be adjusted to utilize hourly load readings where more disaggegated data are not available.

Finally, the model can be readily tailored to forecast and analyze peak electric power demand at the individual utility level and has been developed to run interactively in a well-known simulation environment.

Footnotes

[1]Canadian Electrical Association, Subject 534 U 551, Survey of Peak Demand Forecasting Techniques, CERI Energy Research Ltd. and Synergic Resources Corporation, report soon to be released.

APPENDIX A

KUPC ORGANIZATION

EUPC Organization

The Council

The EUPC Council provides a forum for the presentation and review of the industry's one-system planning activities and government policy concerns, and serves as a Board of Directors for the organization, providing direction to the Steering Committee.

The Council is composed of senior executives from the utility members, advisory members from three provincial departments, (Utilities and Telecommunications, Environment, and Energy and Natural Resources) plus observing members from regulatory agencies.

Steering Committee

The Steering Committee is responsible for the day-to-day management of co-ordinated one-system planning, reporting to the Council on such planning activities and carrying out directives of the Council. Composed of senior representatives of Alberta Power Limited, Trans-Alta Utilities, Edmonton Power and The City of Calgary Electric System, the Steering Committee directs and co-ordinates the activities of the EUPC's working committees and task forces.

Forecast Committee

The Forecast Committee is responsible for producing an annual forecast indicating the projected requirements for electric energy during the ensuing 25 years. The report is prepared after the use of a variety of information-gathering techniques and exhaustive study of economic, demographic and social trends within Alberta. The committee's annual forecast forms the basis for the work of other EUPC committees. The Forecast Committee also continually monitors electric energy usage in the province and updates its forecast as required.

System Evaluation and Reliability Committee

Using the load forecast, members of the System Evaluation and Reliability Committee (SERCOM) analyse the expected system reliability of the Alberta Interconnected System and recommend to the Steering Committee generation expansion sequences within accepted criteria for reliability.

Power Development Evaluation Committee

The Power Development Evaluation Committee (DEVCOM) assesses possible generation addition sequences (provided by SERCOM) that would expand the generating capacity in the province, and recommends to the Steering Committee which sequence best meets the economic, social and environmental concerns of the EUPC and the citizens of the province.

Transmission Committee

The Transmission Committee is responsible for recommending the sequence of development of the facilities by which electric energy is moved from generation facilities to the province's load centres, from which it can be distributed to its eventual users. When proposals are made to build new generating stations, the Transmission Committee determines which transmission alternative will best integrate the new generation into the Alberta Interconnected System. The committee also reviews and co-ordinates the short-range transmission planning of individual utilities to ensure compatibility with long-term EUPC plans.

External Ties Committee

The objective of the External Ties Committee is to investigate how transmission lines interconnected to electric systems outside Alberta may best be used in developing expansion options for planning the Alberta Interconnected System. As one of its functions, the committee recommends general principles for agreements with utilities outside of Alberta, although the committee does not carry out detailed contractual negotiations with such utilities.

Communications Committee

The Communications Committee is responsible for ensuring that interested persons in government and among the public are kept aware of the EUPC's activities and the status of electric energy generation and transmission planning in the province. The committee produces annual and special reports for the EUPC, and advises and assists the Steering Committee and its working committees on communications strategies.

Water Resources Committee

The objectives of the Water Resources Committee are to assess the potential of using provincial water resources for hydro and thermal power generation, and to monitor the policies of governments, boards and licensees where they may affect current and future power utility requirements. The assessments carried out by the committee will provide sufficient cost information to enable an analysis and/or ranking to be undertaken.

Alternative Energy Resources and Technologies Committee

Although coal, hydro and gas are the energy sources for the majority of the province's current generation of electric power, it is necessary for the EUPC to remain abreast of developments in other sources and technologies that are not currently in use. The Alternative Energy Resources and Technologies Committee monitors this area and analyses the potential of new energy sources.

Fee Administration Committee

The Fee Administration Committee is responsible for the allocation of disbursements made by the EUPC and its Council members.

Task Forces

Task forces are established by the Steering Committee from time to time to deal with issues that require special attention. They may be active for a relatively short time, or may be ongoing from year to year, depending on the nature of the project they are working on. During 1985, two task forces were active: the Acid Deposition Task Force and the Socio-economic and Environmental Task Force.

SOURCE: Electric Utility Planning Council. 1985 Review.

APPENDIX B

COMPARISON OF ELECTRICITY SALES

TABLE B.1

COMPARISON OF ACTUAL AND BASE CASE (GW.H)

YEAR	RESIDENTIAL ACTUAL	RESIDENTIAL BASE	COMMERCIAL ACTUAL	COMMERCIAL BASE	STREET ACTUAL	STREET BASE
1970	1818.7	1688.9	2641.8	2651.9	146.8	142.4
1971	2037.1	1894.6	2934.2	2926.7	155.9	151.0
1972	2248.5	2214.4	3247.0	3232.5	167.8	163.2
1973	2458.7	2456.5	3569.9	3560.0	178.8	176.6
1974	2669.4	2754.4	3969.1	3967.2	195.4	200.2
1975	2914.6	3150.6	4326.0	4356.2	204.8	205.3
1976	3099.2	2983.9	4703.2	4678.4	219.6	209.7
1977	3288.5	3242.5	4952.3	5057.1	234.6	220.6
1978	3687.1	3668.8	5372.2	5379.5	248.6	235.5
1979	4050.9	4261.8	5921.8	5920.2	258.8	266.1
1980	4258.6	4548.8	6502.9	6533.5	275.3	290.5
1981	4540.5	4688.4	7133.1	7098.0	291.5	310.3
1982	5052.8	5199.7	7773.7	7612.3	300.7	303.6
1983	4994.0	4789.1	7951.4	8101.3	293.8	298.3
1984	5117.9	4589.7	8293.3	8210.4	294.7	293.0
TOTAL	52236.8	52132.1 **	79292.0	79285.1 **	3467.2	3466.4
DIFFERENCE:						
1970-84		104.65		6.90		0.76

TABLE B.1(CONTINUED)

COMPARISON OF ACTUAL AND BASE CASE (GW.H)

YEAR	FARM ACTUAL	FARM BASE	PIPE ACTUAL	PIPE BASE	URBAN TR ACTUAL	URBAN TR BASE	OILSANDS ACTUAL	OILSANDS BASE
1970	545.1	547.6	294.1	375.8	17.6	19.5	0	0
1971	612.8	607.2	366.1	471.1	17.3	17.8	0	0
1972	648.1	661.5	573.6	499.8	17.3	16.2	0	0
1973	684.0	702.8	888.9	1056.1	16.2	13.9	0	0
1974	777.4	760.7	751.4	875.2	15.2	12.9	0	0
1975	807.5	804.3	553.9	459.5	11.2	10.7	26.8	29.1
1976	860.9	863.0	455.8	504.3	9.8	10.0	52.7	49.1
1977	896.9	885.4	485.9	485.8	9.3	9.9	79.6	54.2
1978	993.3	972.3	480.6	473.2	9.1	9.3	59.9	87.0
1979	1074.9	1048.5	601.2	783.4	8.6	8.9	68.1	76.2
1980	1087.9	1101.0	570.8	601.1	8.0	8.8	111.9	164.4
1981	1121.0	1125.8	493.7	435.3	17.3	25.7	163.9	172.9
1982	1265.2	1248.9	480.6	367.2	27.5	24.6	206.6	147.6
1983	1256.4	1229.1	571.9	398.7	28.7	27.0	272.3	288.6
1984	1326.1	1389.3	659.2	507.6	34.9	27.9	331.3	252.4
TOTAL	13957.7	13947.4	**8227.9	8294.0	** 248.0	243.1	** 1373.2	1321.4
DIFFERENCE: 1970-84		10.31		-66.17		4.87		51.75

TABLE B.1(CONTINUED)

COMPARISON OF ACTUAL AND BASE CASE (GW.H)

YEAR	OILFIELDS ACTUAL	OILFIELDS BASE	GAS ACTUAL	GAS BASE	GASPROCESS ACTUAL	GASPROCESS BASE	REFINERY ACTUAL	REFINERY BASE
1970	424.1	364.1	433.1	436.7	29.2	29.3	79.0	107.4
1971	511.8	511.6	496.2	500.1	41.8	39.5	140.3	130.6
1972	630.8	625.9	635.9	595.5	58.7	53.8	156.8	152.2
1973	789.2	760.3	710.5	691.1	59.7	62.8	166.7	160.2
1974	873.1	941.7	720.5	757.3	60.3	67.0	187.4	174.0
1975	877.4	981.7	710.5	726.5	61.2	61.8	245.4	239.2
1976	881.8	932.7	749.9	750.4	61.7	56.7	323.4	287.9
1977	966.8	939.6	789.2	822.2	62.1	65.7	334.3	332.0
1978	1043.1	1019.1	810.0	800.9	124.7	322.1	352.1	365.6
1979	1232.7	1148.3	883.6	964.3	267.7	441.1	365.0	381.5
1980	1361.0	1350.4	942.0	978.0	281.2	374.5	373.5	420.6
1981	1487.7	1585.5	1027.6	1181.2	314.5	443.0	380.7	487.7
1982	1649.1	1571.7	1155.2	1054.5	471.1	380.4	400.2	363.4
1983	1772.2	1762.2	1322.1	1140.5	842.2	342.3	512.3	471.6
1984	1927.5	1888.6	1489.3	1227.8	1121.0	427.8	704.9	509.0
TOTAL	16428.6	16383.4	**12875.7	12627.1	** 3857.0	3167.9	** 4722.1	4582.6
DIFFERENCE:								
1970-84		45.26		248.64		689.11		139.47

TABLE B.1(CONTINUED)

COMPARISON OF ACTUAL AND BASE CASE (GW.H)

YEAR	CHEMICAL ACTUAL	CHEMICAL BASE	FOREST ACTUAL	FOREST BASE	CEMENT ACTUAL	CEMENT BASE	COAL ACTUAL	COAL BASE	OTHER ACTUAL	OTHER BASE
1970	680.6	630.7	43.1	42.4	108.9	112.2	145.0	117.3	707.0	722.4
1971	715.5	671.4	52.6	43.1	113.3	112.3	200.1	179.1	768.2	801.4
1972	815.2	731.2	71.1	77.7	122.7	115.8	210.4	247.9	836.3	905.7
1973	761.8	764.7	93.6	97.7	125.2	120.1	206.0	230.7	908.7	948.1
1974	890.5	852.7	79.5	98.0	127.7	123.9	218.3	225.9	936.4	998.3
1975	864.4	871.0	84.8	87.8	121.5	137.1	255.7	239.0	995.3	989.6
1976	930.4	966.5	109.0	78.4	165.7	146.0	288.9	279.7	1095.5	1020.9
1977	1042.3	1056.8	126.1	98.2	164.0	153.2	330.0	316.2	1190.3	1081.2
1978	1153.9	1160.4	130.8	119.1	169.0	163.0	365.4	361.5	1331.4	1132.7
1979	1265.0	1353.7	140.8	159.0	174.2	180.6	418.6	401.2	1429.4	1264.0
1980	1476.6	1563.2	151.3	160.1	165.7	177.0	458.5	460.2	1465.6	1349.5
1981	1634.3	1790.2	157.0	150.9	235.1	269.3	496.7	505.5	1492.2	1488.8
1982	1668.3	1761.0	137.1	101.8	257.2	252.7	545.7	546.1	1436.6	1510.4
1983	1817.2	1703.1	165.0	187.5	249.6	229.4	574.2	600.6	1464.1	1673.5
1984	2254.8	1735.6	186.2	222.5	219.2	212.0	644.2	632.3	1587.6	1859.7
TOTAL	17970.8	17612.3	** 1728.0	1724.2	**2519.1	2504.6	**5357.8	5343.2	** 17644.5	17746.4
DIFFERENCE:										
1970-84		358.53		3.75		14.42		14.60		-101.90

TABLE B.1(CONTINUED)

COMPARISON OF ACTUAL AND BASE CASE (GW.H)

YEAR	TOTAL INDUSTRIAL ACTUAL	TOTAL INDUSTRIAL BASE	TOTAL SALES ACTUAL	TOTAL SALES BASE	LOSSES ACTUAL	LOSSES BASE	TOTAL SUPPLY ACTUAL	TOTAL SUPPLY BASE
1970	2650.0	2562.5	8114.2	7988.8	1305.7	1036.2	9419.9	9024.9
1971	3039.9	2989.0	9163.3	9057.3	1190.4	1136.5	10353.7	10193.8
1972	3537.9	3505.7	10440.2	10293.3	1288.4	1248.7	11728.6	11542.0
1973	3821.4	3835.8	11617.9	11801.5	1297.6	1380.8	12915.5	13182.3
1974	4093.7	4238.9	12471.6	12809.4	1183.2	1466.7	13654.8	14276.0
1975	4243.0	4362.9	13061.1	13349.5	1453.1	1511.9	14514.2	14861.4
1976	4659.1	4568.3	14007.6	13817.4	1467.4	1550.8	15475.0	15368.2
1977	5084.7	4919.3	14952.3	14820.6	1754.5	1632.8	16706.8	16453.4
1978	5540.5	5531.3	16331.4	16269.9	1747.6	1748.9	18079.0	18018.8
1979	6245.2	6370.0	18161.5	18659.1	1806.2	1934.4	19967.7	20593.5
1980	6787.3	6997.9	19490.8	20081.6	2188.9	2041.9	21679.7	22123.5
1981	7389.7	8075.2	20986.8	21758.8	2126.9	2166.1	23113.7	23924.9
1982	7927.1	7689.5	22827.6	22445.7	2197.9	2216.2	25025.5	24661.9
1983	8991.4	8399.2	24087.7	23242.7	2438.9	2273.8	26526.6	25516.5
1984	10466.1	8967.7	26192.1	23985.6	2304.6	2327.1	28496.7	26312.7
TOTAL	84476.8	83013.1 **	241906.2	240381.2 **	25751.3	25672.7 **	267657.5	266053.9
DIFFERENCE:								
1970-84		1463.64		1524.96		78.64		1603.60

TABLE B.2

COMPARISON OF BASE AND IMPACT CASES (GW.H)

YEAR	CEMENT BASE	CEMENT IMPACT 5%	CEMENT IMPACT 10%	CHEMICAL BASE	CHEMICAL IMPACT 5%	CHEMICAL IMPACT 10%	COAL BASE	COAL IMPACT 5%	COAL IMPACT 10%
1970	112.2	111.6	110.9	630.7	624.9	619.0	117.3	117.2	117.1
1971	112.3	111.8	111.3	671.4	665.6	659.9	179.1	178.9	178.7
1972	115.8	115.4	115.0	731.2	725.4	719.5	247.9	247.6	247.4
1973	120.1	119.9	119.7	764.7	758.7	752.7	230.7	230.6	230.4
1974	123.9	123.5	123.0	852.7	845.7	838.6	225.9	225.8	225.7
1975	137.1	136.2	135.4	871.0	862.8	854.7	239.0	238.8	238.6
1976	146.0	145.6	145.1	966.5	958.2	949.9	279.7	279.4	279.2
1977	153.2	152.3	151.4	1056.8	1048.0	1039.2	316.2	316.0	315.8
1978	163.0	162.6	162.2	1160.4	1149.6	1138.8	361.5	361.2	361.0
1979	180.6	179.6	178.6	1353.7	1341.0	1328.3	401.2	400.9	400.6
1980	177.0	176.3	175.6	1563.2	1549.2	1535.2	460.2	459.9	459.6
1981	269.3	268.0	266.6	1790.2	1774.7	1759.1	505.5	504.9	504.3
1982	252.7	252.3	252.0	1761.0	1745.6	1730.2	546.1	545.4	544.8
1983	229.4	228.7	228.1	1703.1	1687.5	1672.0	600.6	600.0	599.3
1984	212.0	211.7	211.5	1735.6	1721.5	1707.3	632.3	631.6	630.8
TOTAL	2504.6	2495.5	2486.4	17612.3	17458.4	17304.5	5343.2	5338.3	5333.3

TABLE B.2(CONTINUED)

COMPARISON OF BASE AND IMPACT CASES (GW.H)

YEAR	COMMERCIAL BASE	COMMERCIAL IMPACT 5%	COMMERCIAL IMPACT 10%	FARM BASE	FARM IMPACT 5%	FARM IMPACT 10%	FOREST BASE	FOREST IMPACT 5%	FOREST IMPACT 10%
1970	2651.9	2636.4	2620.9	547.6	544.3	541.0	42.4	40.5	38.7
1971	2926.7	2909.8	2892.8	607.2	603.8	600.4	43.1	41.3	39.4
1972	3232.5	3213.8	3195.1	661.5	657.3	653.2	77.7	74.4	71.1
1973	3560.0	3539.4	3518.8	702.8	698.4	693.9	97.7	93.6	89.5
1974	3967.2	3944.2	3921.3	760.7	756.0	751.2	98.0	93.8	89.6
1975	4356.2	4330.7	4305.3	804.3	799.8	795.2	87.8	84.1	80.4
1976	4678.4	4651.2	4624.0	863.0	858.1	853.2	78.4	75.1	71.8
1977	5057.1	5027.5	4998.0	885.4	880.1	874.8	98.2	94.1	90.0
1978	5379.5	5348.4	5317.3	972.3	966.8	961.3	119.1	114.1	109.0
1979	5920.2	5886.1	5852.0	1048.5	1042.3	1036.0	159.0	152.1	145.2
1980	6533.5	6495.8	6458.1	1101.0	1094.2	1087.4	160.1	153.1	146.2
1981	7098.0	7057.0	7016.0	1125.8	1119.2	1112.7	150.9	144.6	138.3
1982	7612.3	7568.2	7524.1	1248.9	1241.4	1234.0	101.8	97.6	93.3
1983	8101.3	8054.0	8006.7	1229.1	1221.2	1213.3	187.5	179.7	171.9
1984	8210.4	8162.5	8114.7	1389.3	1381.9	1374.5	222.5	213.3	204.2
TOTAL	79285.1	78825.1	78365.2	13947.4	13864.7	13782.1	1724.2	1651.4	1578.5

TABLE B.2(CONTINUED)

COMPARISON OF BASE AND IMPACT CASES (GW.H)

YEAR	GAS BASE	GAS IMPACT 5%	GAS IMPACT 10%	GASPROCESS BASE	GASPROCESS IMPACT 5%	GASPROCESS IMPACT 10%	URBAN TR BASE	URBAN TR IMPACT 5%	URBAN TR IMPACT 10%
1970	436.7	416.6	396.4	29.3	27.8	26.2	19.5	19.0	18.5
1971	500.1	477.1	454.1	39.5	37.3	35.2	17.8	17.3	16.8
1972	595.5	568.1	540.7	53.8	50.9	48.0	16.2	15.8	15.4
1973	691.1	659.7	628.3	62.8	59.4	55.9	13.9	13.5	13.1
1974	757.3	721.9	686.4	67.0	63.3	59.6	12.9	12.5	12.2
1975	726.5	693.1	659.7	61.8	58.4	55.0	10.7	10.4	10.2
1976	750.4	716.2	681.9	56.7	53.6	50.6	10.0	9.7	9.5
1977	822.2	784.7	747.1	65.7	62.1	58.5	9.9	9.7	9.4
1978	800.9	763.5	726.0	322.1	304.9	287.7	9.3	9.1	8.9
1979	964.3	920.0	875.6	441.1	417.0	392.9	8.9	8.7	8.4
1980	976.0	933.1	888.1	374.5	354.3	334.0	8.8	8.5	8.3
1981	1181.2	1127.1	1073.1	443.0	419.3	395.5	25.7	25.0	24.4
1982	1054.5	1006.2	958.0	380.4	360.3	340.1	24.6	24.0	23.3
1983	1140.5	1087.8	1035.2	342.3	323.7	305.1	27.0	26.3	25.6
1984	1227.8	1171.0	1114.2	427.8	404.3	380.8	27.9	27.2	26.5
TOTAL	12627.1	12046.0	11464.9	3167.9	2996.5	2825.0	243.1	236.8	230.4

TABLE B.2(CONTINUED)

COMPARISON OF BASE AND IMPACT CASES (GW.H)

YEAR	OILFIELDS BASE	OILFIELDS IMPACT 5%	OILFIELDS IMPACT 10%	OTHER BASE	OTHER IMPACT 5%	OTHER IMPACT 10%	OILSANDS BASE	OILSANDS IMPACT 5%	OILSANDS IMPACT 10%
1970	364.1	356.3	348.6	722.4	714.8	707.2	0	0	0.0
1971	511.6	500.5	489.5	801.4	792.9	784.5	0	0	0.0
1972	625.9	612.3	598.7	905.7	896.0	886.2	0	0	0.0
1973	760.3	744.1	727.9	948.1	938.0	927.9	0	0	0.0
1974	941.7	921.1	900.5	998.3	987.9	977.4	0	0	0.0
1975	981.7	960.5	939.2	989.6	979.0	968.3	29.1	28.0	26.9
1976	932.7	912.8	892.9	1020.9	1009.9	998.8	49.1	47.3	45.5
1977	939.6	919.7	899.9	1081.2	1070.0	1058.7	54.2	52.2	50.2
1978	1019.1	997.9	976.8	1132.7	1120.6	1108.5	87.0	83.7	80.4
1979	1148.3	1124.0	1099.6	1264.0	1250.4	1236.8	76.2	73.4	70.6
1980	1350.4	1322.0	1293.6	1349.5	1334.7	1320.0	164.4	158.2	152.0
1981	1585.5	1552.4	1519.3	1488.8	1473.3	1457.9	172.9	166.3	159.8
1982	1571.7	1539.3	1506.9	1510.4	1494.3	1478.3	147.6	142.0	136.5
1983	1762.2	1724.7	1687.1	1673.5	1655.8	1638.1	288.6	277.4	266.3
1984	1888.6	1848.3	1808.0	1859.7	1840.3	1820.9	252.4	243.2	234.0
TOTAL	16383.4	16035.9	15688.5	17746.4	17558.0	17369.6	1321.4	1271.8	1222.1

TABLE B.2(CONTINUED)

COMPARISON OF BASE AND IMPACT CASES (GW.H)

YEAR	PIPE BASE	PIPE IMPACT 5%	PIPE IMPACT 10%	REFINERY BASE	REFINERY IMPACT 5%	REFINERY IMPACT 10%	RESIDENTIAL BASE	RESIDENTIAL IMPACT 5%	RESIDENTIAL IMPACT 10%
1970	375.8	364.1	352.4	107.4	105.3	103.1	1688.9	1655.5	1622.1
1971	471.1	456.5	441.9	130.6	127.9	125.3	1894.6	1857.1	1819.6
1972	499.8	484.4	469.0	152.2	149.2	146.1	2214.4	2170.7	2127.0
1973	1056.1	1023.5	991.0	160.2	157.1	154.0	2456.5	2407.7	2358.9
1974	875.2	847.7	820.2	174.0	170.4	166.9	2754.4	2699.7	2645.1
1975	459.5	445.2	430.9	239.2	234.3	229.5	3150.6	3086.2	3025.8
1976	504.3	488.7	473.1	287.9	282.2	276.5	2983.9	2924.9	2865.9
1977	485.8	470.6	455.3	332.0	325.6	319.3	3242.5	3178.1	3113.8
1978	473.2	458.6	444.0	365.6	358.1	350.7	3668.8	3596.3	3523.8
1979	783.4	759.3	735.1	381.5	373.7	366.0	4261.8	4177.6	4093.4
1980	601.1	582.5	564.0	420.6	412.1	403.5	4548.3	4459.1	4369.4
1981	435.3	421.9	408.4	487.7	478.2	468.8	4688.4	4595.6	4502.9
1982	367.2	355.7	344.2	363.4	355.9	348.4	5199.7	5097.2	4994.7
1983	398.7	386.3	373.8	471.6	462.2	452.7	4789.1	4694.4	4599.6
1984	507.6	491.8	476.0	509.0	498.8	488.6	4589.7	4498.7	4407.7
TOTAL	8294.0	8036.7	7779.3	4582.6	4491.0	4399.3	52132.1	51100.9	50069.6

TABLE B.2(CONTINUED)

COMPARISON OF BASE AND IMPACT CASES (GW.H)

YEAR	STREET BASE	IMPACT 5%	IMPACT 10%	TOTAL SALES BASE	IMPACT 5%	IMPACT 10%	LOSSES BASE	IMPACT 5%	IMPACT 10%	TOTAL BASE	SUPPLY IMPACT 5%	IMPACT 10%
1970	142.4	140.0	137.5	7988.8	7874.2	7759.7	1036.2	1025.2	1014.2	9024.9	8899.4	8773.9
1971	151.0	148.4	145.9	9057.3	8926.3	8795.2	1136.5	1124.3	1112.2	10193.8	10050.6	9907.4
1972	163.2	160.4	157.6	10293.3	10141.6	9989.9	1248.7	1235.1	1221.5	11542.0	11376.7	11211.4
1973	176.6	173.6	170.6	11801.5	11617.1	11432.6	1380.8	1364.9	1348.9	13182.3	12982.0	12781.6
1974	200.2	196.6	193.0	12809.4	12610.1	12410.8	1466.7	1449.8	1432.9	14276.0	14059.9	13843.7
1975	205.3	201.7	198.1	13349.5	13151.2	12953.0	1511.9	1495.4	1478.8	14861.4	14646.6	14431.8
1976	209.7	206.0	202.4	13817.4	13618.8	13420.2	1550.8	1534.3	1517.8	15368.2	15153.2	14938.1
1977	220.6	216.8	213.0	14820.6	14607.5	14394.3	1632.8	1615.5	1598.1	16453.4	16223.0	15992.5
1978	235.5	231.4	227.3	16269.9	16026.8	15783.7	1748.9	1729.6	1710.3	18018.8	17756.5	17494.0
1979	266.1	261.5	257.0	18659.1	18367.7	18076.3	1934.4	1912.1	1889.8	20593.5	20279.8	19966.1
1980	290.5	285.5	280.5	20081.6	19778.6	19475.5	2041.9	2019.2	1996.4	22123.5	21797.7	21471.8
1981	310.3	304.8	299.4	21758.8	21432.5	21106.2	2166.1	2142.1	2118.1	23924.9	23574.6	23224.3
1982	303.6	298.1	292.7	22445.7	22123.7	21801.6	2216.2	2192.7	2169.2	24661.9	24316.4	23970.8
1983	298.3	293.0	287.8	23242.7	22902.6	22562.6	2273.8	2249.3	2224.7	25516.5	25151.9	24787.2
1984	293.0	287.8	282.6	23985.6	23633.9	23282.2	2327.1	2301.9	2276.7	26312.7	25935.8	25558.8
TOTAL	3466.4	3405.8	3345.3	240381.2	236812.6	233244.0	25672.7	25391.6	25109.5	266053.9	262204.2	258353.4

APPENDIX C

MODEL SIMULATION OF NORMALIZED LOAD SHAPES (1986) FOR SELECTED SALES CATEGORIES DAY OF SYSTEM PEAK

FIGURE C.1
COAL LOAD SHAPE
1986

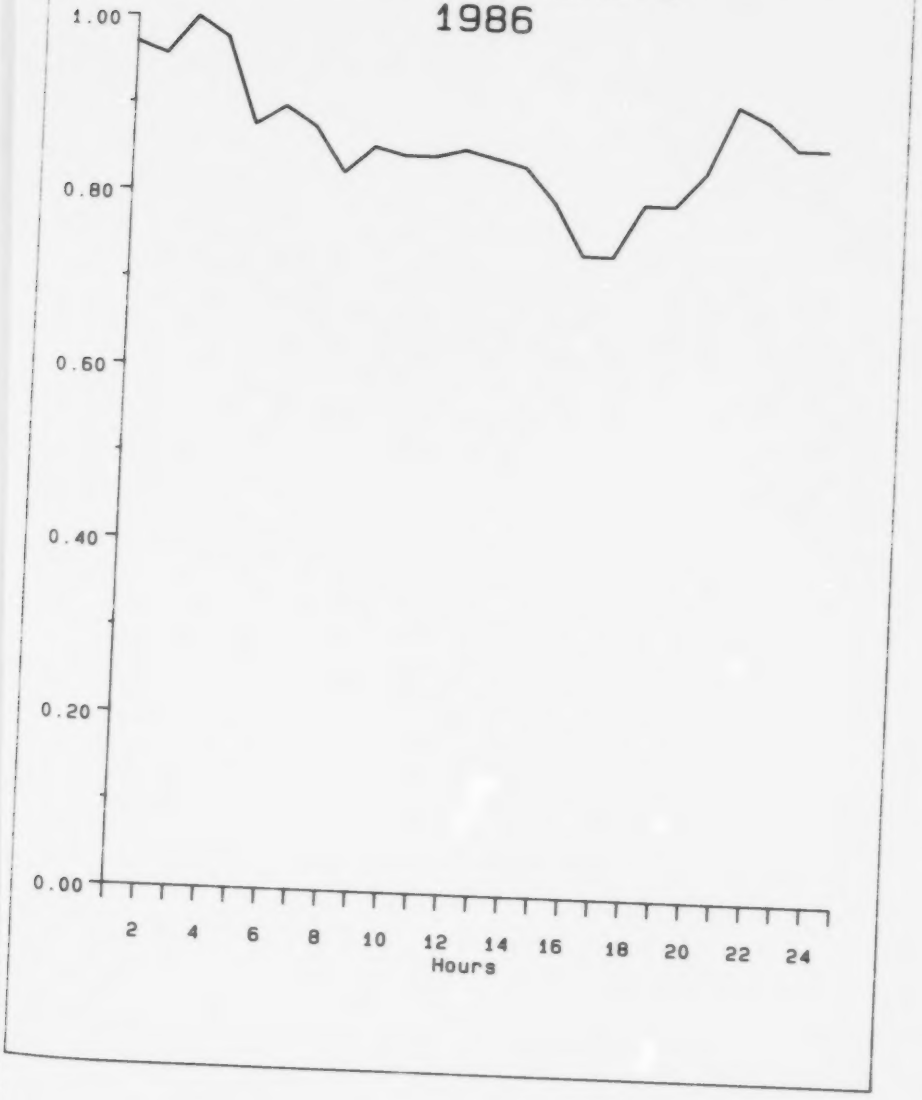


FIGURE C.2
COMMERCIAL LOAD SHAPE
1986

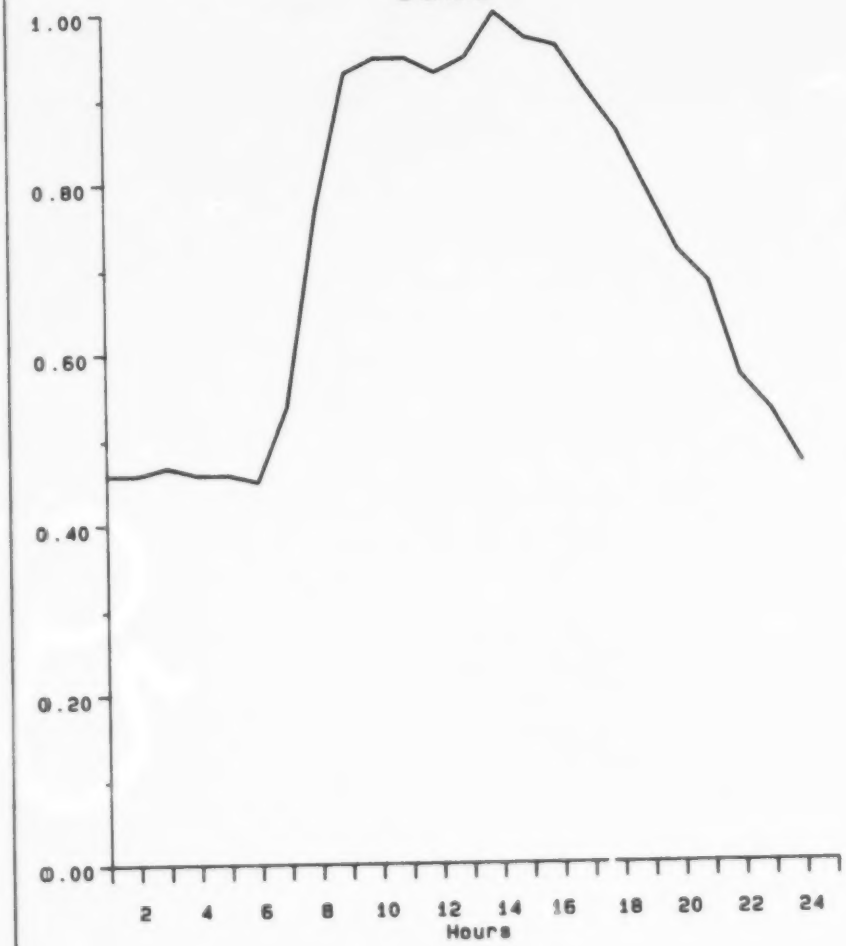


FIGURE C.3
FARMING LOAD SHAPE
1986

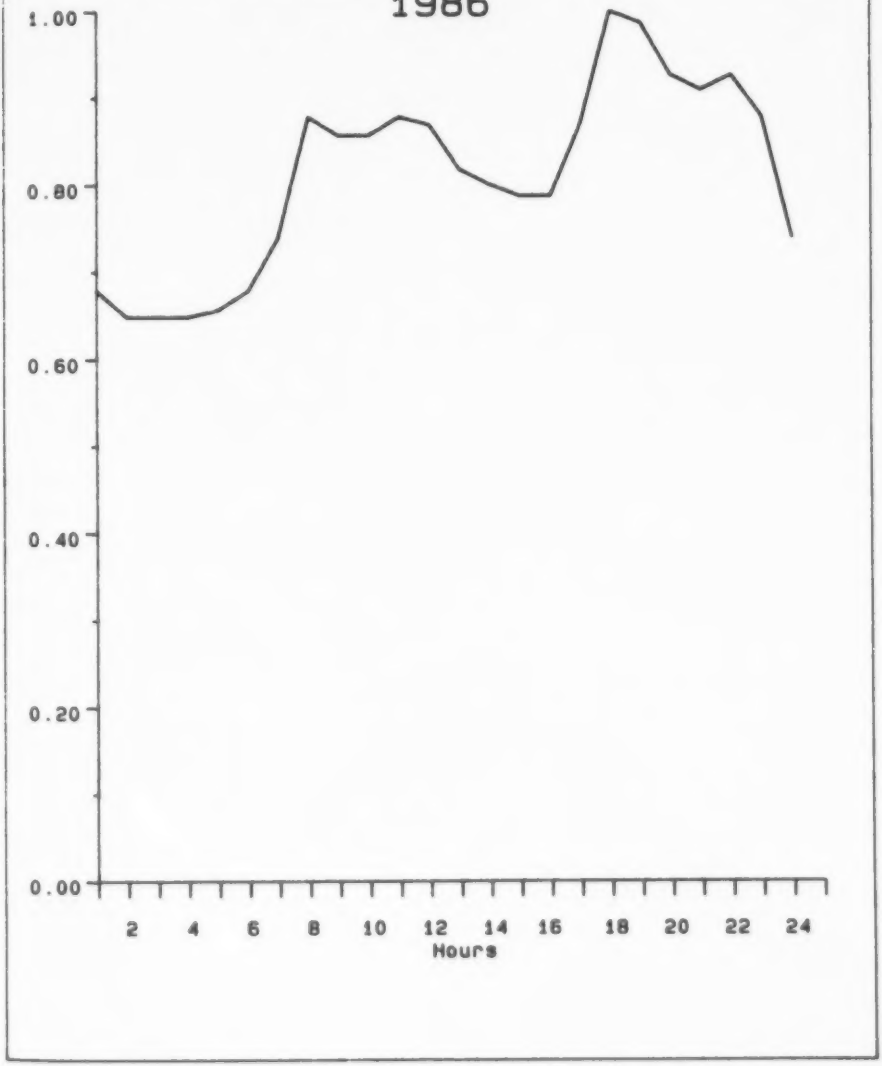


FIGURE C.4
FORESTRY LOAD SHAPE
1986

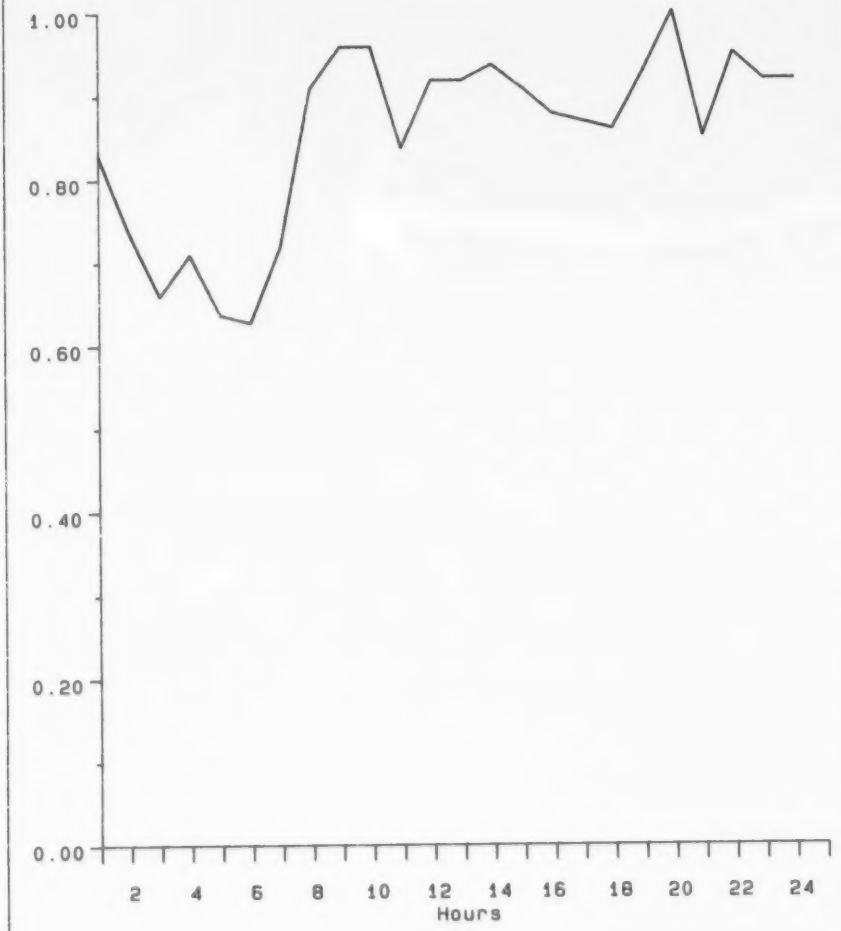


FIGURE C.5
OIL FIELDS LOAD SHAPE
1986

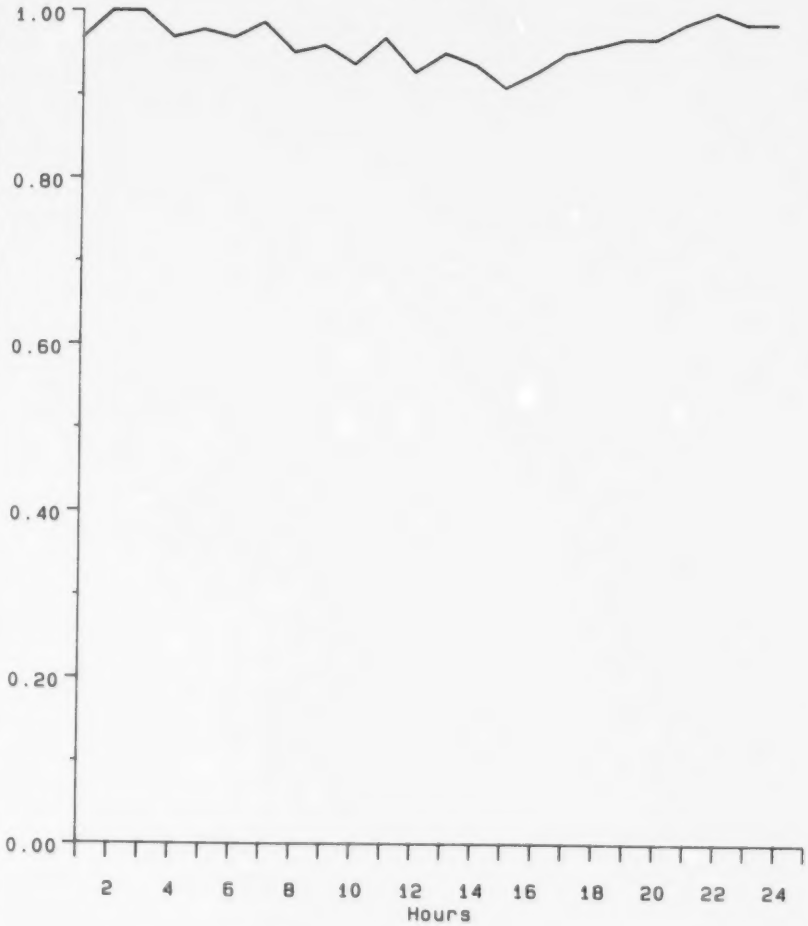


FIGURE C.6
OTHER INDUSTRIES LOAD SHAPE
1986

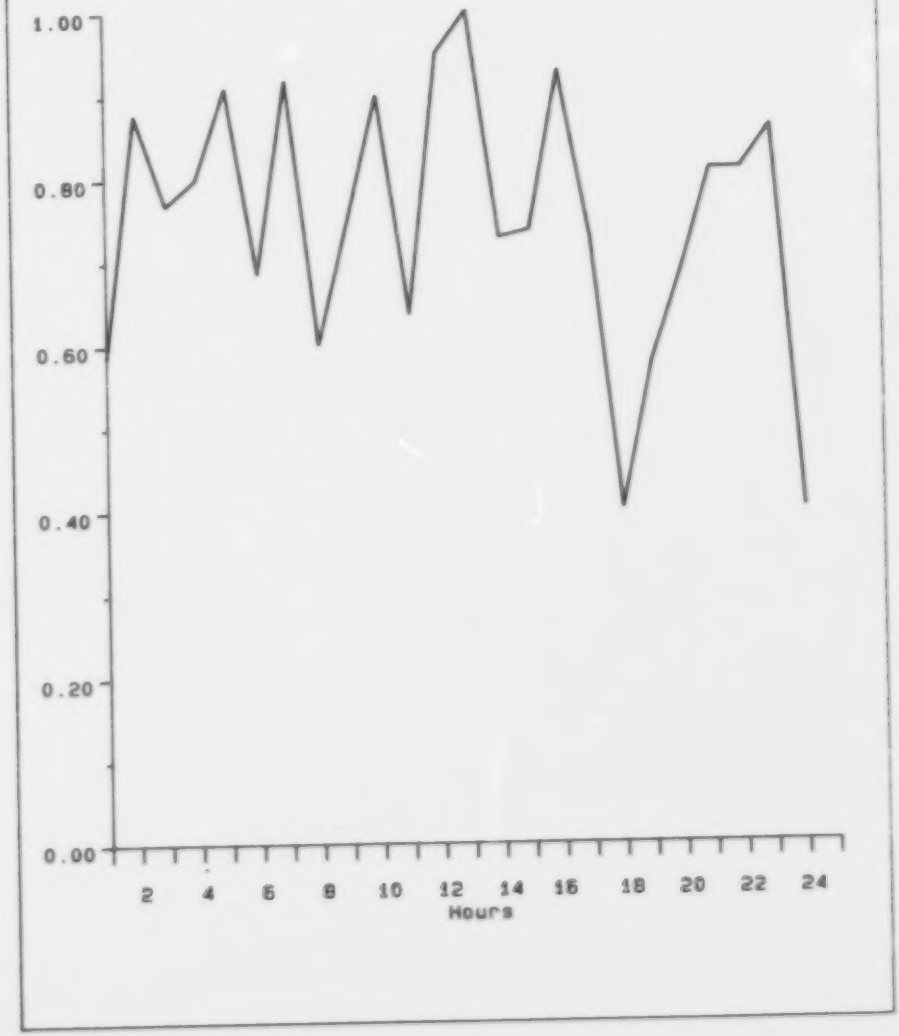


FIGURE C.7
PIPELINES LOAD SHAPE
1986

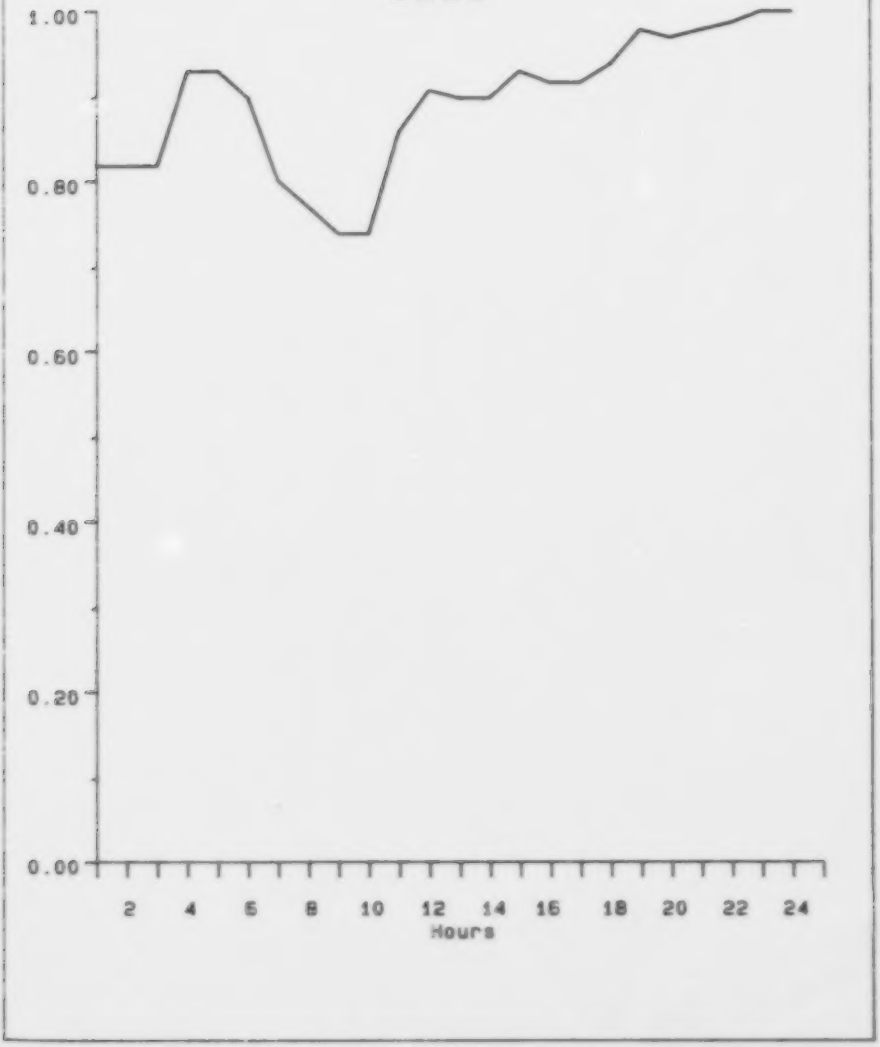


FIGURE C.8
GAS PLANTS LOAD SHAPE
1986

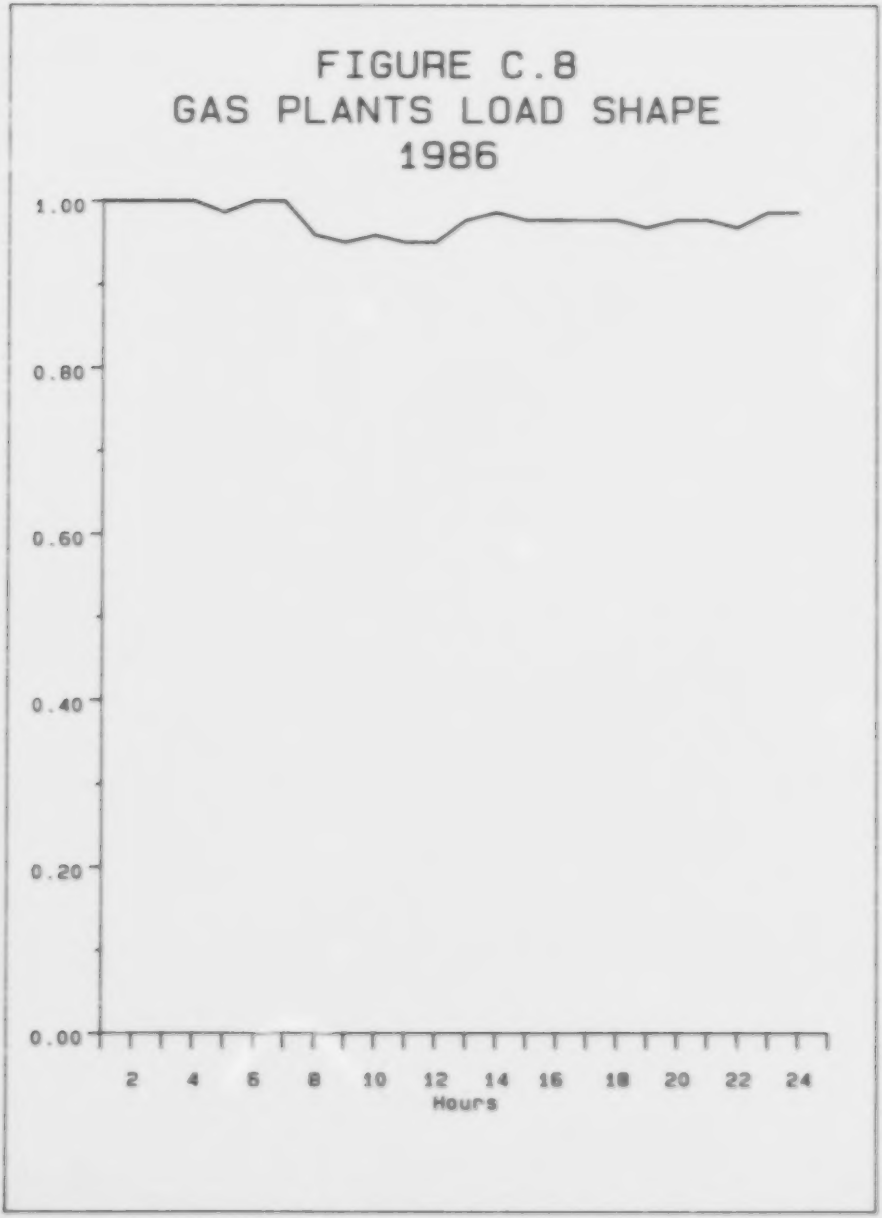
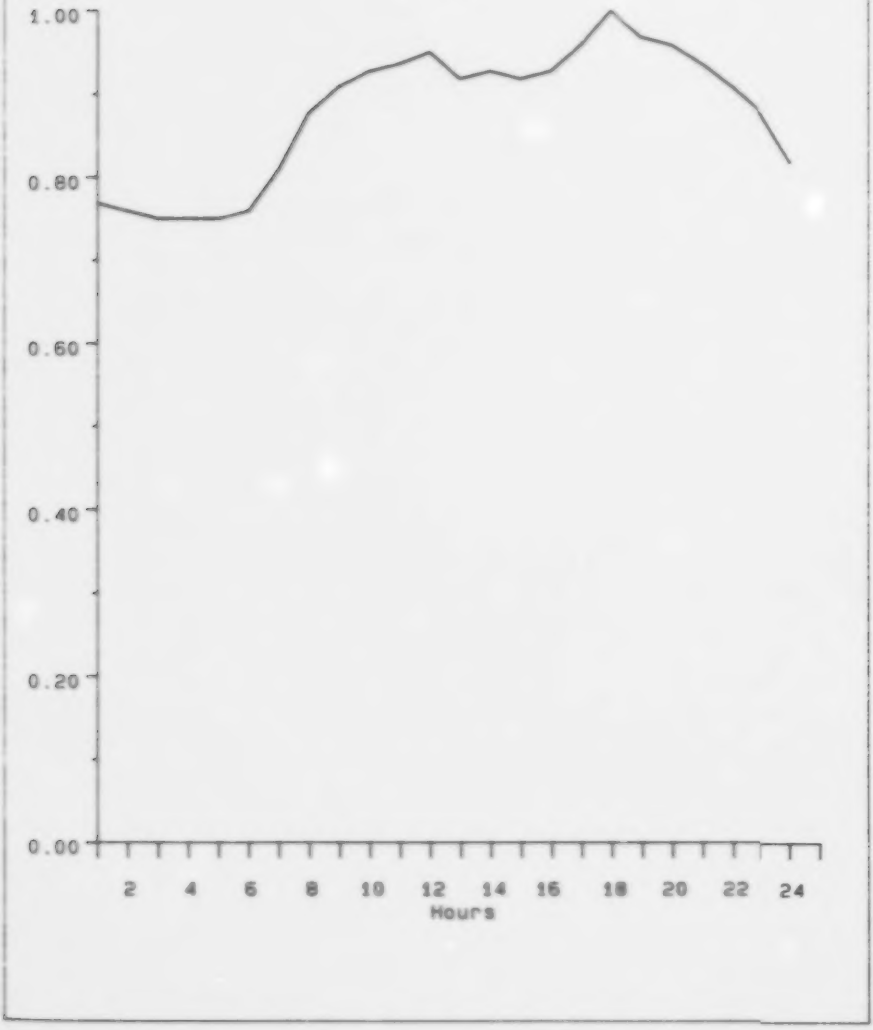


FIGURE C.9
AIS SYSTEM LOAD SHAPE
1986



APPENDIX D

GLOSSARY OF TERMS

Appendix D

GLOSSARY OF TERMS

Abstracted from Glossary of Terms, The Canadian Electrical Association, March 1983.

AVERAGE REVENUE PER KILOWATT-HOUR SOLD (AVERAGE PRICE OF ELECTRICITY): Revenue from the sale of electricity (exclusive of forfeited discounts and penalties) for a particular class of service divided by the corresponding number of kilowatt-hours sold.

CLASS OF SERVICE: A group of customers with similar characteristics (i.e., residential, commercial, farm, industrial, general service, municipal, wholesale, lighting, etc.) which are identified for the purpose of setting a rate for electric service.

COGENERATION: Non-utility owned electric generation permitted to operate in parallel with an electric utility system under stipulated conditions.

COINCIDENCE FACTOR: The ratio of the coincident maximum demand of two or more loads to the sum of their non-coincident maximum individual demands for a given period. It is the reciprocal of the diversity factor and is always less than or equal to one.

CUSTOMER CLASS: A distinction between users of electrical energy. Customer class is usually defined by usage patterns, usage levels, and conditions of service.

DEGREE-DAY: A unit measuring the extent to which the outdoor mean (average of maximum and minimum) daily dry-bulb temperature falls below (in the case of heating) or rises above (in the case of cooling) an assumed base. The base is normally taken at 18° C for heating and for cooling unless otherwise designated. One degree-day is counted for each degree of deficiency below (for heating) or excess over (for cooling) the assumed base, for each calendar day on which such deficiency or excess occurs.

DEMAND: The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment; expressed in kilowatts, kilovoltamperes, or other suitable unit at a given instant or averaged over any designated period of time. The primary source of "DEMAND" is the power-consuming equipment of the customers.

ANNUAL MAXIMUM: The greatest of all demands of the load under consideration which occurred during a prescribed demand interval in a year.

ANNUAL SYSTEM MAXIMUM: The greatest demand on an electric system during a prescribed demand interval in a year.

COINCIDENT: The sum of two or more demands which occur in the same demand interval.

INSTANTANEOUS PEAK: The maximum demand at the instant of greatest load.

DIVERSITY: That characteristic of variety of electric loads whereby individual maximum demands usually occur at different times. Diversity among customers' loads results in diversity among the loads of distribution transformers, feeders, and substations, as well as between entire systems.

DIVERSITY FACTOR: The ratio of the sum of the noncoincident maximum demands of two or more loads to their coincident maximum demand for the same period, which is always equal to or greater than one.

ELASTICITY OF DEMAND: The ratio of the percentage change in quantity demanded for a good to the percentage change in price, keeping everything else constant. Demand is elastic when the absolute value of the ratio exceeds 1.0 and inelastic when it is less than 1.0. Demand is used here as an economics term (i.e., the quantity of a good required by consumers) rather than as an engineering term (kilowatts), so that there can be a price elasticity of demand for energy and a price elasticity of demand for power.

ENERGY CONSERVATION: The more efficient use of energy resources. Energy conservation seeks to reduce energy invested per unit of product output, service performed, or benefit received through waste reduction. Energy conservation and energy use reduction are not necessarily synonymous.

GIGAWATTS: 10^9 Watts or 10^6 kilowatts.

LOAD: The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power consuming equipment of the customers.

LOAD CURVE: A curve on a chart showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.

LOAD DIVERSITY: The difference between the sum of the maxima of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts.

LOAD DURATION CURVE: A curve showing hourly loads during a specified period arranged in descending order of magnitude. The coordinates may be absolute quantities, or percentages. Load duration curves are frequently used to determine the hours of operation each year of each generating unit on a system.

LOAD FACTOR: The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

LOAD FORECAST: An estimate of electrical demand or energy consumption at some future time.

LOAD MANAGEMENT: Techniques designed to level the time patterns of electricity generation, usually in order to increase the utility system load factor, reduce peak demand, and to conserve energy.

LOAD SURVEY: The various steps and processes generally used in making load analyses; i.e., selecting loads to be studied, collecting and analyzing load data and presenting the load characteristics data in useful form.

LOSS (LOSSES): The general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system. Losses occur principally as energy transformation from kilowatt-hours to waste heat in electrical conductors and apparatus.

OFF-PEAK: Periods of low system demands as specified by the supplier.

SEASONAL PEAK: The maximum demand placed on the utility's capacity resulting from seasonal factors. Some utilities have summer peaks, some winter peaks, and some both. In Canada, the main system peaks are all in the winter, although some parts of the system may have a summer peak.

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